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Evaluation of the Advanced Low-NOx Burner, Exxon, and Hitachi Zosen DeNOx Processes

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16. ABSTRACT

The report is a technical discussion and preliminary economic evaluation of six NOx control methods: three at 50% NOx reduction, and three at 90%. The base-case power plant is a new 500-MW coal-fired unit emitting 0.6 lb NO_2/million Btu in the flue gas. The three 50% NOx reduction processes are the EPA-sponsored advanced low-NOx burner (ALNB), the Exxon Thermal DeNOx process, and the Hitachi Zosen process, which have capital investments of $4.8, $19.7, and $31.4/kW, respectively, and levelized annual revenue requirements of 0.20, 1.9, and 4.7 mills/kWh, respectively. For 90% NOx reduction, the ALNB process is combined with the Hitachi Zosen process, the Exxon process is combined with the Hitachi Zosen process, and the Hitachi Zosen process is used alone. Capital investment and levelized annual revenue requirements for these three processes are $51.8/kW and 6.7 mills/kWh for the ALNB/Hitachi Zosen process, $64.2/kW and 8.2 mills/kWh for the Exxon/Hitachi Zosen process, and $50.9/kW and 7.9 mills/kWh for the Hitachi Zosen process alone. The ALNB, a combustion modification, is the least expensive NOx control method. As expected, the costs for obtaining high levels of NOx reduction (90%) are significantly greater than for more moderate levels (50%).

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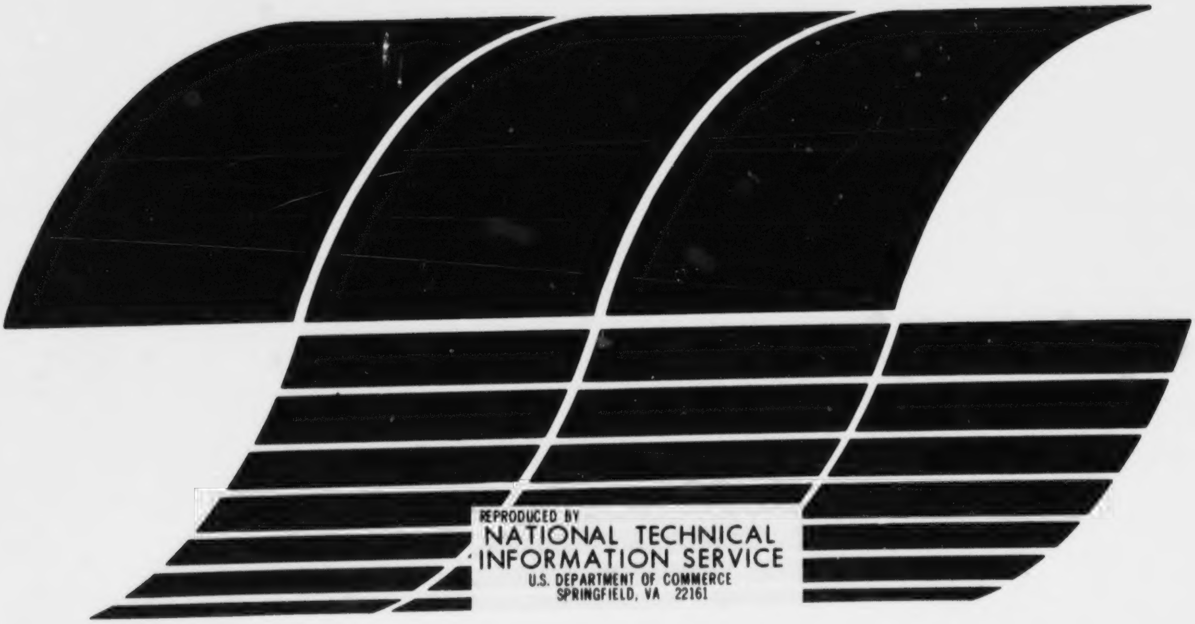
Interagency Energy/Environment R&D Program Report



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Evaluation of the Advanced Low-NO_x Burner, Exxon, and Hitachi Zosen DeNO_x Processes

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ABSTRACT

A technical discussion and a preliminary economic evaluation are made for three nitrogen oxide (NO_x) emission control methods at 50% NO_x reduction and three NO_x control methods at 90% NO_x reduction. The base-case power plant is a new 500-MW coal-fired unit emitting 0.6 lb NO_2/MBtu in the flue gas. The three 50% NO_x reduction processes are the EPA-sponsored advanced low-NO_x burner (ALNB), the Exxon Thermal DeNO_x process, and the Hitachi Zosen process, which have capital investments of $4.8/kW, $19.7/kW, and $31.4/kW, respectively, and levelized annual revenue requirements of 0.20, 1.9, and 4.7 mills/kWh respectively. For 90% NO_x reduction, the ALNB process is combined with the Hitachi Zosen process, the Exxon process is combined with the Hitachi Zosen process, and the Hitachi Zosen process is used alone. Capital investment and levelized annual revenue requirements for these three processes are $51.8/kW and 6.7 mills/kWh for the ALNB/Hitachi Zosen process, $64.2/kW and 8.2 mills/kWh for the Exxon/Hitachi Zosen process, and $50.9/kW and 7.9 mills/kWh for the Hitachi Zosen process. The ALNB, a combustion modification, is the least expensive NO_x control method. As would be expected, the costs for obtaining high levels of NO_x reduction (90%) are significantly greater than for more moderate levels (50%).

CONTENTS

Abstract iii
Figures vii
Tables ix
Abbreviations and Conversion Factors x

Executive Summary xiii

Introduction 1

Background 3
  NO_x Control Regulations 3
  NO_x Formation Chemistry 3
  Status of Technology 4
    Combustion Modification 4
    Flue Gas Treatment 8

Status of Processes Evaluated 12
  Advanced Low-NO_x Burner 12
    Process Description 12
    Technical Considerations 14
    Development Status 19
  Exxon Process 22
    Process Description 22
    Technical Considerations 29
    Development Status 30
  Hitachi Zosen Process 31
    Process Description 31
    Technical Considerations 33
    Development Status 40

Premises 45
  Design Premises 45
    Plant Size and Fuel 45
    Flue Gas Composition 46
    NO_x Control System 46
    Raw Materials 48
  Economic Premises 48
    Capital Investment Estimates 49
    Annual Revenue Requirements 51

Systems Estimated 53
  Advanced Low-NO_x Burner 53
  Exxon Process 57

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NH3 Storage and Injection 57
Air Preheater Section 57
Hitachi Zosen Process 61
Process Description (90% NO_x reduction) 62
Process Description (50% NO_x reduction) 67

Results and Comparison 72
Capital Investment 72
Fifty Percent NO_x Reduction 72
Ninety Percent NO_x Reduction 73
Overall Capital Investment Comparison 74
Annual Revenue Requirements 76
Fifty Percent NO_x Reduction 77
Ninety Percent NO_x Reduction 77
Overall Annual Revenue Requirements Comparison 78
Overall Capital Investment and Annual Revenue Requirements Comparison 81
Energy Consumption 81

Conclusions 86

References 88

Appendix A 91

Appendix B 109

FIGURES

Number — Page

S-1 Assumed NO_x reduction for the six cases studied xv
S-2 Cost for reduction of a pound of NO_x based on levelized annual revenue requirements xxii
S-3 Capital investment comparison and accuracy range (based on a -20% to +40% range for Exxon and Hitachi Zosen processes and a -20% to +100% range for the ALNB) xxiv
S-4 Levelized annual revenue requirements and accuracy range (based on a -20% to +40% range for Exxon and Hitachi Zosen processes and a -20% to +100% range for the ALNB) xxv
1 Baseline NO_x emissions - coal-fired utility boilers 5
2 Pulverized-coal-fired boiler burner zone heat release rates 6
3 Major stages of the ALNB development 13
4 Alternatives for injection of ALNB tertiary air 14
5 Effects of ALNB zone stoichiometry, single burner 15
6 Effects of ALNB primary swirl, single burner 16
7 Effects of ALNB secondary swirl, single burner 17
8 Effects of ALNB zone stoichiometry, four burners fired at 12.5 x 10^6 Btu/hr each 18
9 Effects of ALNB tertiary ports out of service, four burners fired at 12.5 x 10^6 Btu/hr each 20
10 Effects of ALNB coal type, four burners fired at 12.5 x 10^6 Btu/hr each 21
11 Variables evaluated in the single ALNB test program 23
12 Effect of temperature on NO reduction for various levels of NH_3 injection with the Exxon process 25
13 Effect of temperature on NO reduction for various fuel sources with the Exxon process 26
14 Comparison of NO reductions at the optimum temperature condition with the Exxon process 27
15 Comparison of the NH_3 emissions for all fuels tested at the peak NO reduction temperature with the Exxon process . 28
16 NO_x reduction versus reaction temperature for the Hitachi Zosen process 34
17 Configuration of Hitachi Zosen NOXNON 500 and 600 series catalyst 35
18 Relationship between exhaust NH_3, NO_x reduction, and molar ratio for the Hitachi Zosen process 36
19 Conditions for the formation of ammonium sulfate/bisulfate 38

20 Pressure drop versus operating time for the Hitachi Zosen process 39
21 NO_x reduction versus catalyst age for the Hitachi Zosen process 37
22 Influence of NO_x concentration on NO_x reduction with the Hitachi Zosen process 41
23 Influence of O_2 concentration on NO_x reduction for the Hitachi Zosen process 42
24 Assumed NO_x reduction for the six cases studied 54
25 Advanced low-NO_x burner flow diagram 55
26 Exxon process flow diagram 58
27 Hitachi Zosen process (90% NO_x reduction) flow diagram . . . 63
28 Hitachi Zosen process (50% NO_x reduction) flow diagram . . . 68
29 Cost for reduction of a pound of NO_x based on levelized annual revenue requirements 82
30 Capital investment comparison and accuracy range (based on a -20% to +40% range for Exxon and Hitachi Zosen processes and a -20% to a +100% range for the ALNB) 83
31 Levelized annual revenue requirements and accuracy range (based on a -20% to +40% range for Exxon and Hitachi Zosen processes and a -20% to +100% range for the ALNB) 84

TABLES

Number — Page

S-1 Summary of Capital Investments xix
S-2 Summary of Annual Revenue Requirements xx
S-3 The Effect of Catalyst Life on Annual Revenue Requirements . . xxi
S-4 Energy Requirements xxvi
1 NO_x Emissions Standards and Projected Research Objectives for Large Fossil-Fuel-Fired Boilers 3
2 Summary of Commercial Applications of Exxon Thermal DeNO_x Process 32
3 Influence of SO_2 and H_2O Concentrations 40
4 Hitachi Zosen Pilot-Plant Experience 43
5 Commercial Plants Using the Hitachi Zosen Process 44
6 Coal Plant Base Mechanical Equipment 45
7 Base Case Coal Composition and Input Flow Rate 46
8 Flue Gas Composition and Flow Rate at the Economizer Outlet . 47
9 Levelized Annual Capital Charges for Regulated Utility Financing 49
10 Cost Indexes and Projections 50
11 Cost Factors 52
12 Advanced Low-NO_x Burner Material Balance 56
13 Exxon Material Balance 59
14 Exxon Equipment List 60
15 Hitachi Zosen (90% NO_x Reduction) Material Balance 64
16 Hitachi Zosen (90% NO_x Reduction) Equipment List 65
17 Hitachi Zosen (50% NO_x Reduction) Material Balance 69
18 Hitachi Zosen (50% NO_x Reduction) Equipment List 70
19 Summary of Capital Investments 73
20 Contribution of Direct Investment, Royalties, and Catalyst to Capital Investment 75
21 Summary of Annual Revenue Requirements 76
22 Contribution of Raw Materials and Utilities to Annual Revenue Requirements 79
23 The Effect of Catalyst Life on Annual Revenue Requirements . . 80
24 Comparison of Energy Requirements 85

ABBREVIATIONS AND CONVERSION FACTORS

ABBREVIATIONS

ac	acre
aft^3/min	actual cubic feet per minute
ALNB	advanced low-NO_x burner
bbl	barrel
Btu	British thermal unit
°F	degrees Fahrenheit
dia	diameter
FGD	flue gas desulfurization
FGT	flue gas treatment
ft	feet
ft^2	square feet
ft^3	cubic feet
gal	gallon
gpm	gallons per minute
gr	grain
hp	horsepower
hr	hour
in.	inch
k	thousand
kW	kilowatt (electric)
kWh	kilowatthour
lb	pound
L/G	liquid to gas ratio in gallons per thousand actual cubic feet of gas at outlet conditions
M	million
mi	mile
mo	month
MW	megawatt (electric)
MW_t	megawatt (thermal)
ppm	parts per million
psig	pounds per square inch (gauge)
rpm	revolutions per minute
RR	first-year annual revenue requirement
SCR	selective catalytic reduction
sec	second
sft^3/min	standard cubic feet per minute (60°F)
S_P	swirl angle, primary air
SNR	selective noncatalytic reduction
SR_B	stoichiometric ratio, total air minus tertiary air
SR_P	stoichiometric ratio, primary air
SR_T	stoichiometric ratio, theoretical
S_S	swirl angle, secondary air
SS	stainless steel
TCI	total capital investment
yr	year

CONVERSION FACTORS

EPA policy is to express all measurements in Agency documents in metric units. Values in this report are given in British units for the convenience of engineers and other scientists accustomed to using the British systems. The following conversion factors may be used to provide metric equivalents.

	To convert British	Multiply by	To obtain Metric	
ac	acre	0.405	hectare	ha
bbl	barrels of oil[a]	158.97	liters	L
Btu	British thermal unit	0.252	kilocalories	kcal
^{o}F	degrees Fahrenheit minus 32	0.5556	degrees Celsius	^{o}C
ft	feet	30.48	centimeters	cm
ft^2	square feet	0.0929	square meters	m^2
ft^3	cubic feet	0.02832	cubic meters	m^3
ft/min	feet per minute	0.508	centimeters per second	cm/s
ft^3/min	cubic feet per minute	0.000472	cubic meters per second	m^3/s
gal	gallons (U.S.)	3.785	liters	L
gpm	gallons per minute	0.06308	liters per second	L/s
gr	grains	0.0648	grams	g
gr/ft^3	grains per cubic foot	2.288	grams per cubic meter	g/m^3
hp	horsepower	0.746	kilowatts	kW
in.	inches	2.54	centimeters	cm
lb	pounds	0.4536	kilograms	kg
lb/ft^3	pounds per cubic foot	16.02	kilograms per cubic meter	kg/m^3
lb/hr	pounds per hour	0.126	grams per second	g/s
psi	pounds per square inch	6895	pascals (newton per square meter)	Pa (N/m^2)
mi	miles	1609	meters	m
rpm	revolutions per minute	0.1047	radians per second	rad/s
sft^3/min	standard cubic feet per minute ($60^{o}F$)	1.6077	normal cubic meters per hour ($0^{o}C$)	m^3/h (normal)
ton	tons (short)[b]	0.9072	metric tons	tonne
ton, long	tons (long)[b]	1.016	metric tons	tonne
ton/hr	tons per hour	0.252	kilograms per second	kg/s

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a. Forty-two U.S. gallons per barrel of oil.

b. All tons, including tons of sulfur, are expressed in short tons in this report.

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EVALUATION OF THE ADVANCED LOW-NO_x BURNER, EXXON, AND HITACHI ZOSEN DENO_x PROCESSES

EXECUTIVE SUMMARY

INTRODUCTION

The new source performance standards (NSPS) for steam electric generating boilers promulgated after the Clean Air Act Amendments of 1977 require the installation of the best available control technology (BACT) for nitrogen oxides (NO_x) on new or modified facilities, including electric power generating units. Therefore, as NO_x control technology is further developed, more stringent standards may be required. The 1977 Clean Air Act Amendments also require the promulgation of a short-term nitrogen dioxide (NO_2) ambient air quality standard (three hours or less averaging time) unless it can be demonstrated that the standard is unnecessary for public health protection. This short-term ambient standard may require additional NO_x emission control for stationary sources. Prevention of significant deterioration (PSD) regulations for NO_2 are also required by the 1977 Clean Air Act Amendments and these requirements may also lead to more stringent NO_x emission control for stationary sources.

There are two basic types of NO_x control technology currently under development: combustion modifications and flue gas treatment (FGT). Combustion modifications primarily include the use of low excess air, staged combustion with either overfire air or burners out of service, flue gas recirculation, burner design and operating modifications, or combinations of the above. Combustion modification techniques have received the most development emphasis in the United States. However, FGT may be needed to achieve the NO_x emission reductions which may be required in the future.

FGT can be divided into two general categories: dry and wet. The majority of dry processes involve a gas-phase reaction with a reducing agent, NH_3, which is added to the flue gas. If the NH_3 is injected into the superheater region of the boiler where temperatures are high (1,740°F), a catalyst is not necessary. These processes are known as selective noncatalytic reduction (SNR) processes. If the flue gas is treated after the boiler economizer, a catalyst is necessary to produce the needed reaction rate. These processes are typically described as selective catalytic reduction (SCR) processes. Development of wet NO_x FGT processes has practically ceased because of the complexity and unfavorable economics of these processes compared with dry processes.

The major purposes of this study are to provide current technical information on the various selected NO_x control methods and to compare the economics of these NO_x control methods using common design and economic premises. The NO_x control techniques selected for evaluation are combustion modification, SNR, and SCR processes. Wet processes are not evaluated. The combustion modification technique evaluated is the advanced low-NO_x burner (ALNB) being developed under the U.S. Environmental Protection Agency (EPA) sponsorship by the Energy and Environmental Research Corporation (EERC); a 50% NO_x reduction capability is assumed for the ALNB in this study. The Exxon Thermal DeNO_x process, an SNR process, is also evaluated; moderate NO_x reduction (30% to 60%) is attainable by this process. The SCR process evaluated in this study is the Hitachi Zosen process. This type of process has the capability for high levels of NO_x reduction (90%).

Two levels of NO_x reduction from NSPS level are examined. Assuming a baseline emission for the boiler of 0.6 lb NO_2/MBtu (450 ppm at 3% O_2) costs are determined for a moderate 50% NO_x reduction to 0.3 lb NO_2/MBtu (225 ppm at 3% O_2) for each of the three processes although 50% NO_x reduction is not typical for the Hitachi Zosen process. The alternative control level, 90% NO_x reduction to 0.06 lb NO_2/MBtu (45 ppm at 3% O_2), involves the following three situations:

1. Moderate NO_x reduction achieved by the ALNB (0.6 to 0.3 lb NO_2/MBtu) and the remaining NO_x reduction (80%) achieved by the Hitachi Zosen process (0.3 to 0.06 lb NO_2/MBtu).

2. Moderate NO_x reduction achieved by the Exxon process (0.6 to 0.3 lb NO_2/MBtu) and the remaining NO_x reduction (80%) achieved by the Hitachi Zosen process (0.3 to 0.06 lb NO_2/MBtu).

3. All of the NO_x reduction (90%) achieved by the Hitachi Zosen process (0.6 to 0.06 lb NO_2/MBtu).

The levels of NO_x reduction assumed for each process and process combination evaluated in this report are graphically illustrated in Figure S-1.

DESIGN AND ECONOMIC PREMISES

A specific set of design and economic premises is used to compare the process economics of the different types of NO_x control technology on a consistent basis. The basic premises used in this report were established by TVA for comparative economic evaluations of power plant stack gas emission control processes.

Design Premises

The power plant assumed as a basis for this study is a new 500-MW, horizontally opposed, balanced-draft boiler burning pulverized coal and situated in a north-central location (Illinois, Indiana, Ohio, Michigan, or

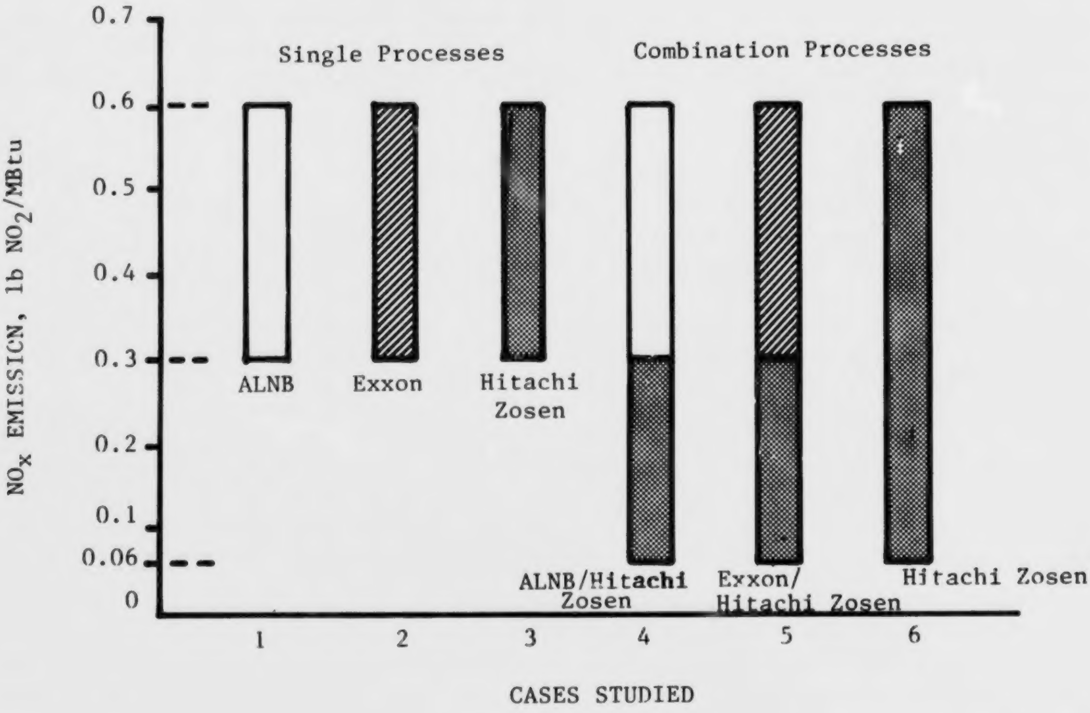

Figure S-1. Assumed NO_x reduction for the six cases studied.

Wisconsin). The fuel is a bituminous coal with a heating value of 11,700 Btu/lb as fired and containing 3.5% sulfur and 15.1% ash. The boiler heat rate is 9,500 Btu/kWh. On-stream time for the boiler is 5,500 hr/yr. Raw materials are assumed to be received by either rail or truck. Thirty-day storage facilities at full load (500 MW) are provided.

The estimated costs for the selected NO_x control methods reported in this study are differential costs for new boilers, i.e., only additional expenses above present new boiler costs are included. Costs are not included for present combustion modification techniques being applied to new boilers, which are reportedly capable of reducing NO_x emissions to the NSPS of 0.6 lb NO_2/MBtu for bituminous coal. In the case of the ALNB, only the differential costs over those for regular burners are included. Also, separate induced draft (ID) fans are not included. Where applicable, a larger boiler ID fan is used to compensate for the higher pressure drops of the combined boiler-NO_x control process and the increased costs are assigned to the NO_x control process.

Economic Premises

Capital investment estimates are based on projected mid-1982 construction costs. The revenue requirements are based on projected 1984 costs. Delivered raw material costs and labor rates are based on a north-central location.

Capital investment consists of direct investment, indirect investment, and other capital investments. The direct investment is based on equipment costs. Other installation costs (such as piping, electrical, instrumentation, etc.) are factored from the equipment costs. Indirect investment (engineering design and supervision, construction expense, etc.) is based on the direct investment. Other capital investments, such as allowance for startup and modification and interest during construction, are based on the total direct and indirect investment. Other capital investments also include, when applicable, land, working capital, royalties, and initial catalyst charges.

Two types of annual revenue requirements are projected—first year and levelized. Both are based on 5,500 hr/yr of operation at full load (about a 63% capacity factor) and both use a levelized capital charge. Levelized annual revenue requirements differ from first-year annual revenue requirements in that they take into consideration the time value of money over the life of the NO_x reduction unit. They are calculated using a 10%/yr discount factor, a 6%/yr inflation factor, and a 30-year economic life.

PROCESS BACKGROUND AND SYSTEMS ESTIMATED

Advanced Low-NO_x Burner

An ALNB for both utility and industrial applications is being developed under EPA sponsorship by EERC to minimize NO_x formation during the combustion of coal. The primary objectives are: (1) to provide an initial fuel-rich, i.e., oxygen-deficient, zone which maximizes the conversion of organic nitrogen coumpounds to N_2, and (2) to blanket the fuel-rich zone with an oxidizing atmosphere to maximize burnout and to minimize the potential for corrosion in the lower furnace section of the boiler. The research goal is to attain an NO_x emission level equivalent to 0.2 lb NO_2/MBtu. For this study, the NO_x emission level assumed for the ALNB is 0.3 lb NO_2/MBtu.

The utility burner design consists of a central burner, similar to the Babcock & Wilcox (B&W) dual register burner, plus four tertiary air ports located about one throat diameter from the central burner. The air admitted through the central burner is divided into three streams referred to as primary and inner and outer secondary air. Primary air that carries the entrained pulverized coal is about 25% of stoichiometric requirements. Secondary air is injected from an annulus around the primary air port and is about 45% of stoichiometric requirements. Swirl vanes in the inner secondary annulus impart swirl to control mixing of the primary and inner secondary streams and to control flame shape. The remaining secondary air is admitted through the outer secondary annulus. About 50% of the stoichiometric air quantity is admitted through the tertiary air ports. Thus, with a total air supply of 120% of stoichiometric requirements, the central burner operates at about 70% stoichiometry to minimize oxygen availability and conversion of fuel nitrogen to NO_x, while the remaining stoichiometric air supplied through the tertiary air ports completes combustion and maintains an overall oxidizing atmosphere.

Exxon Process

The Exxon process, developed by Exxon Research and Engineering, reduces NO_x in flue gas by dry SNR. NH_3 with air (94-98 volume % air) is injected into the cavity of the secondary superheater tube bank region where the temperature is high enough for NO_x and NH_3 to react to form N_2 and H_2O. For NO_x reduction of 40% to 60%, the optimum temperature range is 1,650°F to 1,830°F, and the NH_3:NO_x molar ratio varies from 1:1 to 2:1. Injecting H_2 with the NH_3 reduces the temperature level at which reaction rates are adequate for efficient NO_x reduction. At H_2:NH_3 molar ratios of about 2:1 NO_x reduction can occur rather rapidly at about 1,290°F. NH_3 is injected through an insulated piping grid which covers the entire cross-sectional area of the flue gas flow path.

Since NO_x reduction is sensitive to temperature, steps must be taken to maintain NO_x reduction efficiency with varying boiler loads. There are many alternative techniques presently used, i.e., the use of one or multiple grids to inject only the NH_3, or one or multiple grids with both NH_3 and H_2 injection. In this study a two grid system injecting only NH_3 is used. An NH_3:NO_x molar ratio of 1.5:1 is assumed to achieve 50% NO_x reduction.

The major equipment for this process includes only NH_3 storage tanks, NH_3 injection grids, and compressors for the air used as the NH_3 carrier. Also included in this study under equipment costs are costs for air heater design and operating modifications that may be necessary when using this process with a coal-fired boiler. (These modifications result from the

NH_4HSO_4 and $(NH_4)_2SO_4$ deposited in the air heater by reaction of NH_3 with SO_3 present in coal-fired flue gas.)

Hitachi Zosen Process

The Hitachi Zosen process is a dry SCR process in which NH_3 is injected into the flue gas and reacts with NO_x selectively, in the presence of a catalyst, to form N_2 and H_2O. The catalyst allows the reaction to proceed rapidly at temperatures in the 600°F to 750°F range. The corrugated catalyst units, made with a proprietary catalyst on a steel support, permit treatment of flue gas with high particulate loadings. Therefore, based on the temperature range and the lack of required particulate removal, flue gas from a coal-fired boiler may be fed directly from the boiler economizer to an NO_x reduction reactor. With NH_3:NO_x molar ratios of 1:1 or greater, 90% NO_x control is reportedly achievable. This process requires only NH_3 storage and injection facilities and a catalytic reactor. In this study an economizer bypass is also included to maintain acceptable reactor temperatures when the boiler load is low. The temperatures during low boiler loads may not be high enough to obtain adequate NO_x control and may also be low enough to allow NH_4HSO_4 and $(NH_4)_2SO_4$ formation in the catalytic reactor. Also, air heater design and operating modifications are included to minimize the potentially adverse effects of these salts, as is done for the Exxon process.

For the case in which overall NO_x reduction is 90%, two reactor trains are used, each treating 50% of the flue gas. An NH_3:NO_x molar ratio of 1:1 is used. For an overall 50% NO_x reduction only one reactor train is used to treat 56% of the flue gas. Again, an NH_3:NO_x molar ratio of 1:1 is used. A third case is for an overall reduction of 80%, but from a lower initial NO_x level (from 0.3 to 0.06 lb NO_2/MBtu). This case is used in combination with either the ALNB or Exxon process to achieve the same overall degree of NO_x reduction as with the Hitachi Zosen 90% NO_x reduction case. Two reactor trains similar in size to the first case are used, but with less catalyst. An NH_3:NO_x molar ratio of 0.9 is used. A catalyst life of one year is assumed for all three cases.

ECONOMIC RESULTS AND COMPARISON

The process economics consist of capital investment, first-year revenue requirements, and levelized annual revenue requirements. Because of the different sources of data, the simplifying assumptions made, and the necessity of projecting costs into the future, these estimates are considered to be accurate to an overall variation of -20% to +40% for the Exxon and Hitachi Zosen processes. For the ALNB the estimates are considered to be accurate to an overall variation of -20% to +100%. This larger range is a result of the less advanced development status of the ALNB and the relative lack of detailed design, equipment needs, and costs in comparison with the NO_x FGT processes. The findings of this report apply only to a new installation.

Results - Capital Investment

The capital investment results for the 50% and 90% NO_x reduction cases are shown in Table S-1. The ALNB has the lowest capital investment of the three 50% NO_x reduction processes studied. Because of the much greater amounts of process equipment, the investments for the Exxon and Hitachi Zosen processes are significantly higher. A royalty fee is not charged for the ALNB technology while royalty fees are $1.5M and $0.5M for the Exxon and Hitachi Zosen processes, respectively. The cost of the initial catalyst charge ($3.7M) represents a large portion of the Hitachi Zosen capital investment.

TABLE S-1. SUMMARY OF CAPITAL INVESTMENTS

Process	Capital investment, mid-1982$ M$	Capital investment, mid-1982$ $/kW
50% NO_x reduction		
ALNB	2.4	4.8
Exxon	9.9	19.7
Hitachi Zosen	15.7	31.4
90% NO_x reduction		
ALNB/Hitachi Zosen	25.9	51.8
Exxon/Hitachi Zosen	32.1	64.2
Hitachi Zosen	25.5	50.9

For 90% NO_x reduction, the Hitachi Zosen and ALNB/Hitachi Zosen processes have similar capital investments, while the investment for the Exxon/Hitachi Zosen process is higher. Royalty fees are $0.5M for the ALNB/Hitachi Zosen and the Hitachi Zosen processes, and $2.0M for the Exxon/Hitachi Zosen process. The initial catalyst charge for the ALNB/Hitachi Zosen and the Exxon/Hitachi Zosen processes costs $5.0M for each process while the Hitachi Zosen process has a cost for the initial catalyst charge of $6.5M. In contrast to the other processes, the royalty fee for the Exxon process is a major cost item. It is equal to 15% of the capital investment.

Although both the Exxon process and the Hitachi Zosen process use NH_3, the equipment costs associated with NH_3 are much larger for the Exxon process. The investment for NH_3 storage and injection with the process is four times larger than that for the Hitachi Zosen 90% NO_x reduction process. This is a result of a larger NH_3 consumption and subsequent larger storage needs, a more intricate and expensive injection grid, and a more expensive air carrier system for the Exxon process.

Results - Annual Revenue Requirements

The first-year and levelized annual revenue requirements for both the 50% and 90% NO_x reduction cases are shown in Table S-2. As with the capital investment, for 50% NO_x reduction the ALNB has significantly lower revenue requirements than the Exxon or Hitachi Zosen processes. The only substantial revenue requirement item for the ALNB is the levelized capital charges, while the Exxon and Hitachi Zosen processes not only have higher capital charges, but also substantial raw material, utility, and maintenance requirements. The annual catalyst replacement cost is a large portion (33%) of the Hitachi Zosen annual revenue requirement.

TABLE S-2. SUMMARY OF ANNUAL REVENUE REQUIREMENTS

	Annual revenue requirements (1984$)			
	First year		Levelized	
Process	M$	Mills/kWh	M$	Mills/kWh
50% NO_x reduction				
ALNB	0.45	0.17	0.54	0.20
Exxon	3.4	1.2	5.1	1.9
Hitachi Zosen	8.0	2.9	13.0	4.7
90% NO_x reduction				
ALNB/Hitachi Zosen	11.5	4.2	18.4	6.7
Exxon/Hitachi Zosen	14.2	5.2	22.6	8.2
Hitachi Zosen	13.3	4.9	21.9	7.9

For 90% NO_x reduction, although the Hitachi Zosen and ALNB/Hitachi Zosen processes have similar capital investments, the Hitachi Zosen process levelized annual revenue requirements are $3.5M higher than those for the ALNB/Hitachi Zosen process due to greater catalyst requirements of the Hitachi Zosen process. The revenue requirements for the Exxon/Hitachi Zosen process are the highest of the three because of higher conversion cost and levelized capital charges. Annual catalyst replacement is required for all three processes. The annual catalyst replacement cost contributes appreciably to the levelized annual revenue requirements: 32% for the ALNB/Hitachi Zosen process, 26% for the Exxon/Hitachi Zosen process, and 34% for the Hitachi Zosen process.

Since a one-year catalyst life is guaranteed it was used as a basis for the cost estimate however, actual catalyst life could be longer. Should a two-year life be obtainable for the Hitachi Zosen process a significant savings can be realized in the annual revenue requirements. Table S-3 shows that a two-year catalyst life will reduce the levelized annual revenue requirements of the Hitachi Zosen (50% NO_x reduction), ALNB/Hitachi Zosen, and Hitachi Zosen (90% NO_x reduction) processes by 30% and the Exxon/Hitachi Zosen process by 24%. Even though this is a significant reduction for the processes requiring catalyst, it is not sufficient to change the cost relationship of the processes. For 50% NO_x reduction the ALNB is still lowest followed by the Exxon and Hitachi Zosen processes and for 90% NO_x reduction the ALNB/Hitachi Zosen remains the lowest followed by the Hitachi Zosen and Exxon/Hitachi Zosen processes.

TABLE S-3. THE EFFECT OF CATALYST LIFE ON

ANNUAL REVENUE REQUIREMENTS

	Annual Hitachi Zosen catalyst replacement cost, M$		Levelized annual revenue requirements, M$	
Process	1-year catalyst life	2-year catalyst life	1-year catalyst life	2-year catalyst life
50% reduction				
Hitachi Zosen	4.3	2.1	13.0	9.0
90% reduction				
ALNB/Hitachi Zosen	5.8	2.9	18.4	12.9
Exxon/Hitachi Zosen	5.8	2.9	22.6	17.1
Hitachi Zosen	7.5	3.7	21.9	14.8

On the basis of cost per pound of NO_2 removed, as shown in Figure S-2, 50% NO_x reduction is substantially less expensive than 90% NO_x reduction, with the exception of the Hitachi Zosen 50% reduction process. The large cost difference between the Hitachi Zosen 50% reduction case and the two other 50% reduction cases occurs because the ALNB and Exxon processes do not require the expensive annual catalyst replacement.

The Hitachi Zosen 50% NO_x reduction case has a slightly higher cost per pound of NO_2 removed than the Hitachi Zosen 90% reduction case for two reasons. First, there is some economy of scale in the capital investment for the 90% reduction case compared with the 50% reduction case. Therefore, the levelized capital charges and maintenance costs, which are factored from the capital investment, are a smaller portion of the annual revenue requirements for the 90% reduction case. Also, certain items are of equal cost at both the 90% and 50% reduction levels, such as operating and analysis labor, resulting in a smaller cost per pound of NO_2 removed at the 90% reduction level.

The NH_3 cost for the Exxon process is over twice that of the Hitachi Zosen process (50% NO_x reduction case) and even 1-1/2 times higher than that

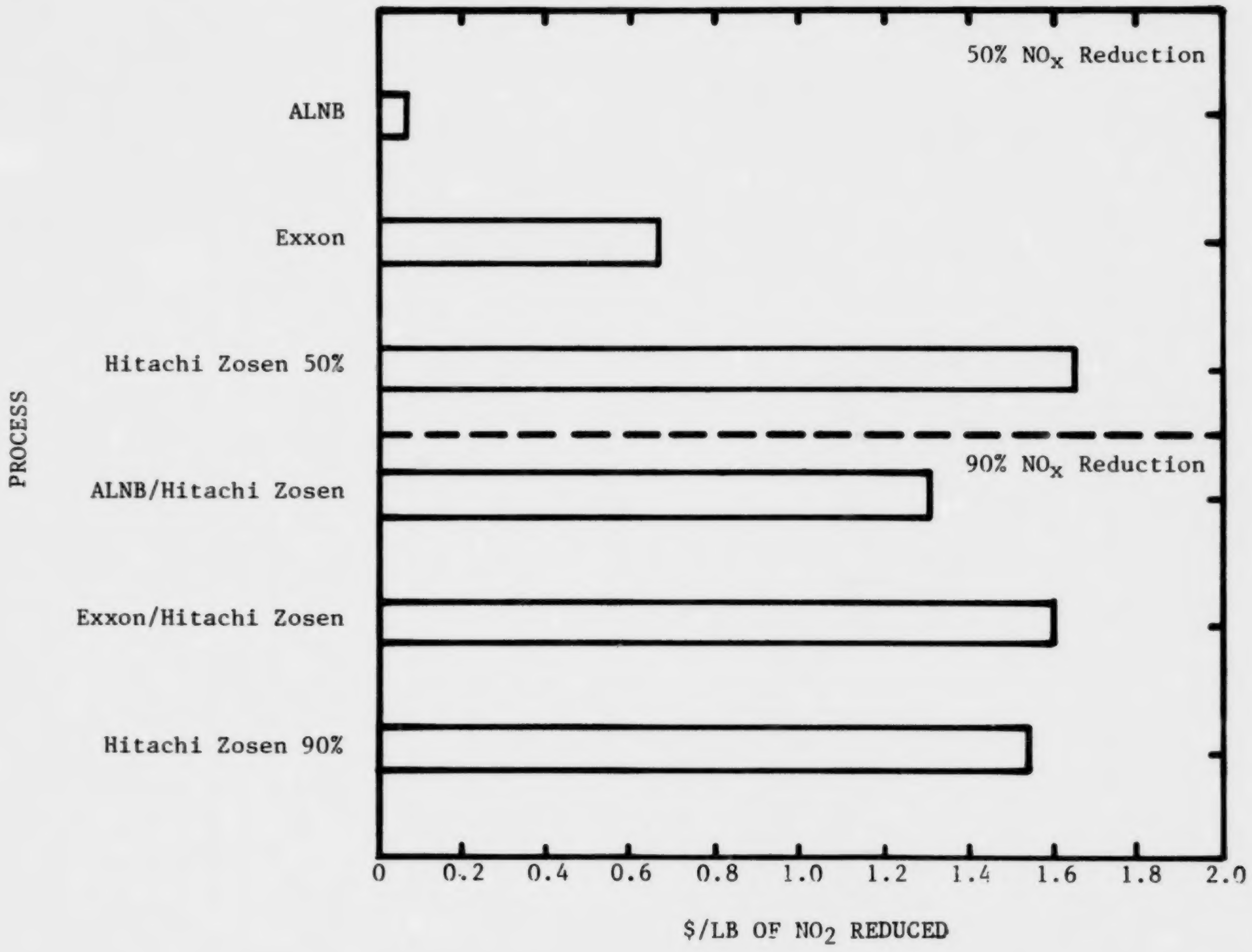

Figure S-2. Cost for reduction of a pound of NO_x based on levelized annual revenue requirements.

for the Hitachi Zosen 90% NO_x reduction process because of the higher NH_3:NO_x molar ratios required. The NH_3 costs are about 15% of the Exxon levelized annual revenue requirements while they are only 2% of the levelized annual revenue requirements for either case of the Hitachi Zosen process.

Overall Capital Investment and Annual Revenue Requirements Comparison

A comparison of the capital investment and levelized annual revenue requirements for each of the six NO_x control processes is shown in Figures S-3 and S-4 respectively. Also included in the figures are the accuracy ranges on the capital investment and levelized annual revenue requirements.

For 50% NO_x reduction the ALNB has the lowest capital investment and levelized annual revenue requirements. The Exxon process has the second lowest and Hitachi Zosen has the highest capital investment and levelized annual revenue requirements.

The capital investment of the ALNB/Hitachi Zosen and the Hitachi Zosen processes are almost equal for 90% NO_x reduction, but the levelized annual revenue requirements are lower for the ALNB/Hitachi Zosen process. In comparison with the above two processes, the Exxon/Hitachi Zosen process capital investment is substantially higher; however, the Exxon/Hitachi Zosen levelized revenue requirement is comparable.

Capital investment and levelized annual revenue requirements are significantly higher for 90% NO_x reduction than for 50% NO_x reduction.

ENERGY CONSUMPTION RESULTS AND COMPARISON

Energy consumption for all the 50% and 90% NO_x reduction cases studied is less than 1% of the boiler capacity, as shown in Table S-4. Energy requirements for the three 50% reduction cases range from none for the ALNB to 0.4% of the boiler capacity for the Exxon process. The range for 90% reduction is from 0.4% of the boiler capacity for the ALNB/Hitachi Zosen and Hitachi Zosen processes to 0.7% of the boiler capacity for the Exxon/Hitachi Zosen process. The NO_x control alternatives containing the Exxon process are the highest energy consumers at both the 50% and 90% NO_x reduction levels.

CONCLUSIONS

The economic conclusions of this study are based on NO_x control technology at various early stages of development applied to a new power plant. Further development and retrofit applications could greatly alter both the absolute and relative costs of the processes. To develop accurate and timely economics in this rapidly evolving field, continued monitoring of developments in NO_x control technology is necessary.

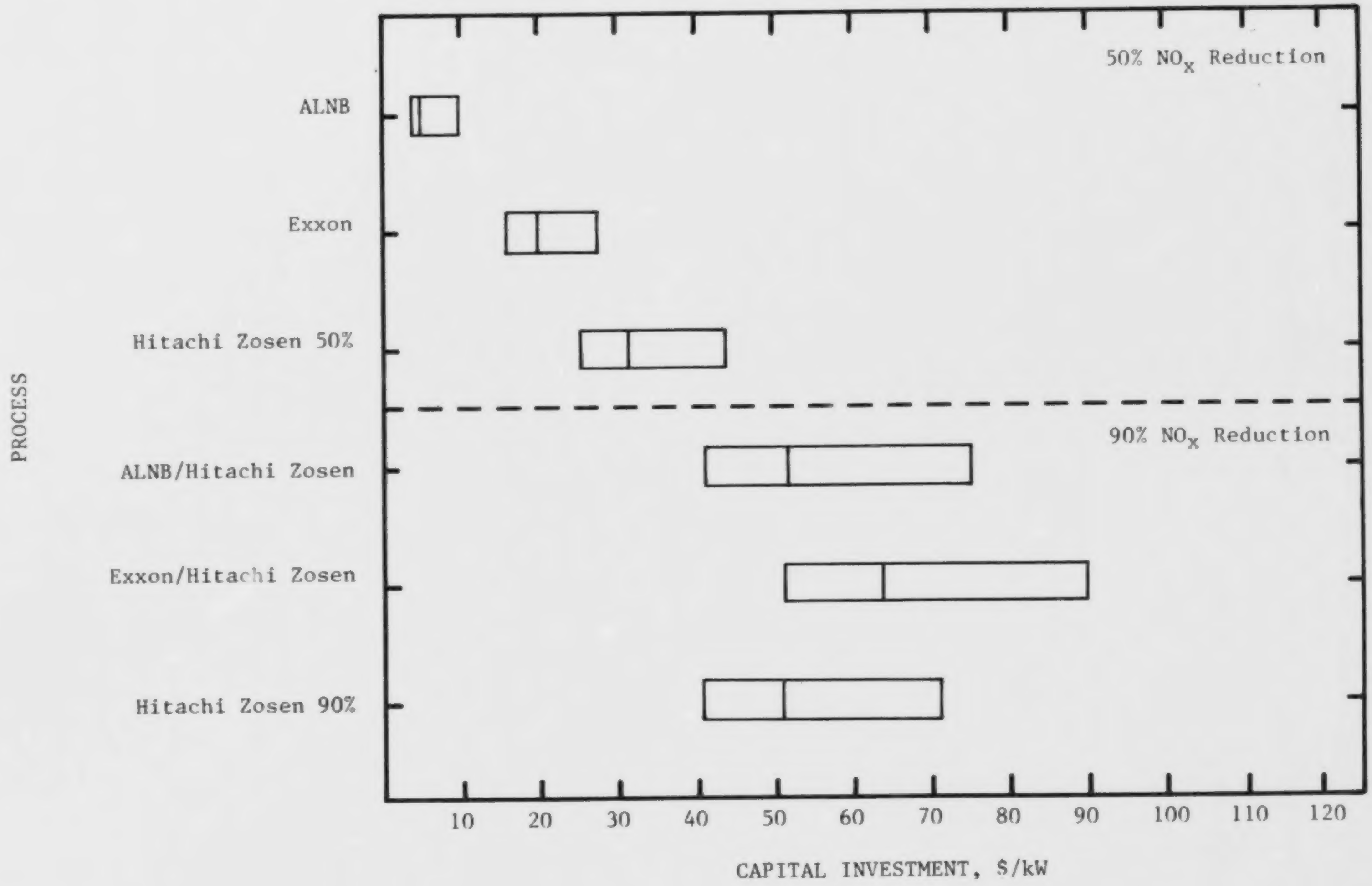

Figure S-3. Capital investment comparison and accuracy range (based on a -20% to +40% range for Exxon and Hitachi Zosen processes and a -20% to +100% range for the ALNB).

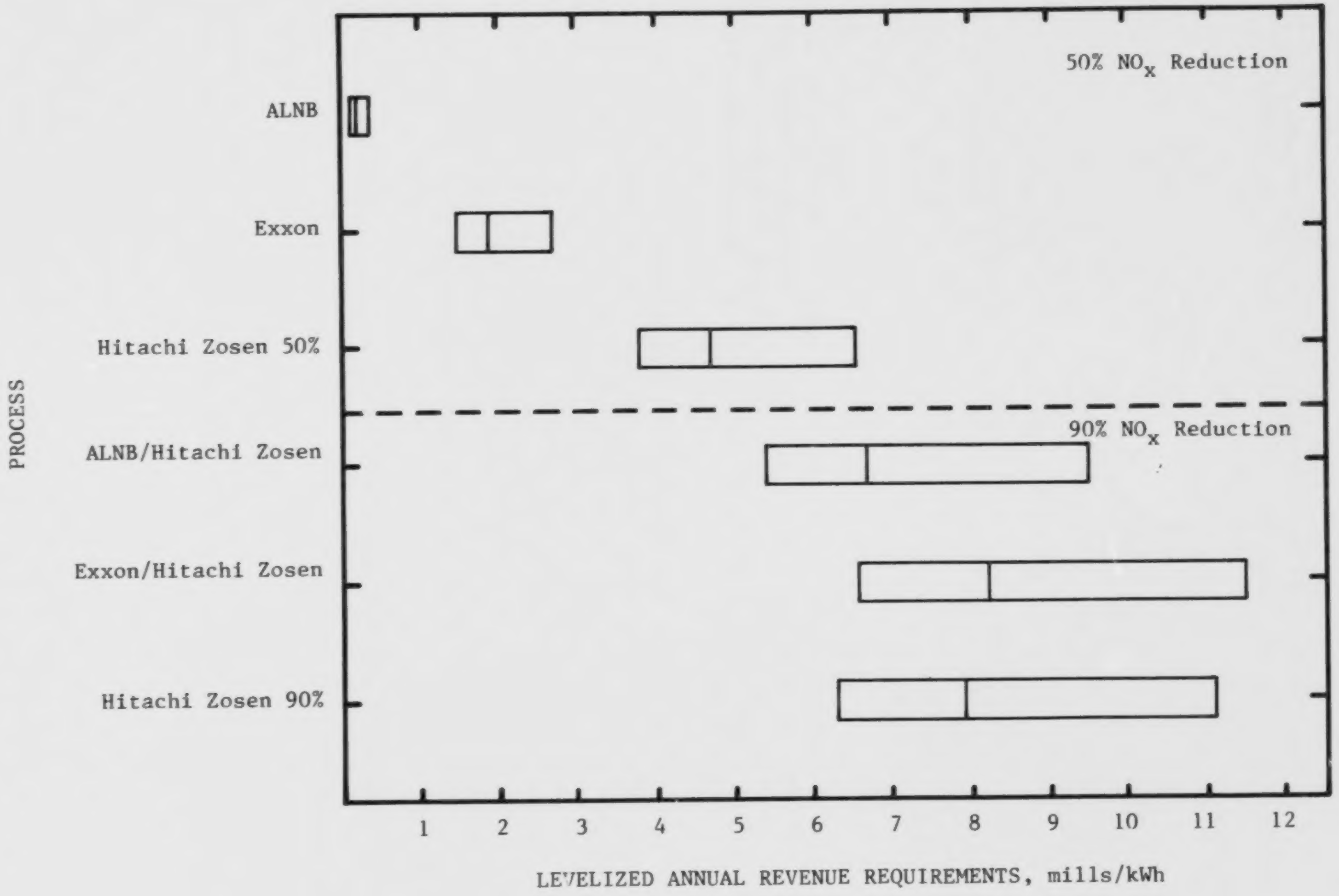

Figure S-4. Levelized annual revenue requirements and accuracy range (based on a -20% to +40% range for Exxon and Hitachi Zosen processes and a -20% to +100% range for the ALNB).

TABLE S-4. ENERGY REQUIREMENTS

Process	Steam, MBtu/hr	Electricity, MBtu/hr	Total equivalent energy consumption, % of boiler capacity[a]
50% reduction			
ALNB	0.0	0.0	0.0
Exxon	5.7	11.5	0.4
Hitachi Zosen	6.0	7.7	0.3
90% reduction			
ALNB/Hitachi Zosen	8.0	10.2	0.4
Exxon/Hitachi Zosen	11.7	21.7	0.7
Hitachi Zosen	10.9	10.3	0.4

a. Does not include energy requirement represented by raw materials. Based on a 500-MW boiler, a gross heat rate of 9,500 Btu/kWh for generation of electricity, and a boiler efficiency of 90% for generation of steam.

For moderate NO_x reduction of 50%, the ALNB is by far the most economical alternative, even if its costs were to increase several times relative to the other processes. The ALNB NO_x reduction efficiency and its effects on boiler efficiency and operation remain to be fully demonstrated in utility applications, however.

The Hitachi Zosen process has a higher capital investment than the Exxon process at the 50% reduction level because of the initial catalyst charge, reactor, additional ductwork, and additional fan capacity required. It also has higher revenue requirements, primarily because of annual catalyst replacement costs, although the NH_3 requirements are much less than those of the Exxon process. Changes in catalyst cost or NH_3 consumption or cost would appreciably affect the cost relationship of these processes.

The royalties for the Exxon process are a significant portion of the capital investment.

For NO_x reductions of 90% the combination of the ALNB/Hitachi Zosen process is, overall, the most cost effective alternative. Although the capital investment for the ALNB/Hitachi Zosen process is slightly higher than the capital investment for the Hitachi Zosen process, the annual revenue requirements are substantially lower. The magnitude of the difference in annual revenue requirements is large enough to overcome the slightly higher capital investment and make the ALNB/Hitachi Zosen process the most economically attractive.

Except for the ALNB the energy requirements to achieve 50% and 90% reduction are greater than those for particulate removal. However, energy requirements for NO_x reduction are still modest, much less than 1% of the boiler output, in comparison with the energy needed for removal of SO_2 from flue gas.

Catalyst cost is a very important economic factor for an SCR-type process. With the Hitachi Zosen process, the catalyst cost may represent as much as 25% of the capital investment and 35% of the levelized annual revenue requirement. Catalyst life is also a very important economic factor. A two-year catalyst life will reduce the levelized annual revenue requirements of the Hitachi Zosen process by about 30%.

Since with current technology it is necessary to use a process such as the SCR-type system to achieve low emission levels (0.06 lb NO_2/MBtu), the costs for obtaining these low levels versus more moderate emission levels (0.3 lb NO_2/MBtu) are substantially greater. Achieving low emission levels, as compared with moderate levels, may result in as much as a tenfold increase in capital investment and a thirtyfold increase in annual revenue requirements.

EVALUATION OF THE ADVANCED LOW-NO_x BURNER, EXXON, AND HITACHI ZOSEN DENO_x PROCESSES

INTRODUCTION

Manmade nitrogen oxide (NO_x) emissions are classified, depending upon their source, as stationary or mobile. Stationary sources are responsible for about 60% of the total U.S. NO_x emissions. Fuel combustion, especially in industrial and utility boilers, produces most of the stationary source NO_x. In fact, industrial and utility boilers firing gas, oil, and coal were responsible for approximately 50% of the manmade NO_x produced in the United States in 1978, with coal-fired utility boilers alone accounting for 22% (27). This and the trend toward increased reliance on coal as the major fuel for electrical energy generation have resulted in greater attention on NO_x control for stationary sources, especially in the utility industry.

There are two basic types of NO_x control technology under development for coal-firing applications: combustion modifications and flue gas treatment (FGT). Combustion modifications primarily include the use of either low excess air, staged combustion with overfired air or burners out of service, flue gas recirculation, burner design and operating modifications, or combinations of the above. Combustion modification techniques have received the most development emphasis in the United States. However, to achieve the NO_x emission reductions that may be required in the future, FGT may be needed.

The majority of FGT processes are dry processes involving a gas-phase reaction with a reducing agent, usually NH_3, that is added to the flue gas. If the NH_3 is injected into the cavities of the secondary superheater zone of the boiler where the temperature is high (1,740°F), a catalyst is not necessary. These processes are known as selective noncatalytic reduction (SNR) processes. If the flue gas is treated after the boiler economizer, where the flue gas temperature is low (730°F), a catalyst is necessary to produce the needed reaction rate. These processes are typically described as selective catalytic reduction (SCR) processes. Presently, development of wet-scrubbing NO_x FGT processes has practically ceased because of the complexity and unfavorable economics of these processes in comparison with the dry processes.

The major purposes of this study are to provide current technical information on the various NO_x control methods being developed and to compare the economics of selected types of NO_x control methods using a set of consistent design and economic premises. The NO_x control techniques selected for evaluation are combustion modifications and SNR and SCR processes. The combustion modification technique evaluated is the advanced low-NO_x burner (ALNB) design being developed under the U.S. Environmental Protection Agency (EPA) sponsorship by the Energy and Environmental Research Corporation (EERC). The Exxon Thermal $DeNO_x$ process, an SNR process, is also evaluated. Although the maximum NO_x reduction is lower than for SCR, moderate NO_x reduction is achievable by this process. The SCR process evaluated in this study is the Hitachi Zosen process. This type of process has the capability of high (90%) levels of NO_x reduction.

Two levels of NO_x reduction are examined. Costs are determined to achieve a moderate NO_x reduction to 0.3 lb NO_2/MBtu (225 ppm at 3% O_2), for each of the three processes. In addition, costs are determined for a greater reduction in NO_x to 0.06 lb NO_2/MBtu (45 ppm at 3% O_2). This degree of NO_x reduction requires either use of the Hitachi Zosen process or combination of the Hitachi Zosen process with one of the other two processes.

The processes evaluated in this study are based on technology provided by the process vendor through mid-1980. Since this time Hitachi Zosen and Exxon have recommended process changes. Although the new technology may slightly affect the cost of each process as presented in this study, the overall comparability between processes should not be affected.

BACKGROUND

NO_x CONTROL REGULATIONS

Following enactment of the Clean Air Act of 1970, EPA promulgated new source performance standards (NSPS) for control of NO_x emissions from fossil-fuel-fired steam electric generating plants in December 1971 (25). Following the 1977 Clean Air Act Amendments, the NSPS were revised by EPA and promulgated in June 1979 (26). The latest standards for large boilers (>250 MBtu/hr) are shown in Table 1. The Clean Air Act Amendments of 1977 require (1) the promulgation of a short-term NO_2 ambient air quality standard (three hours or less averaging time), and (2) the prevention of significant deterioration (PSD) regulations for NO_x. These standards may result in additional NO_x emission control on electric power generating facilities.

TABLE 1. NO_x EMISSIONS STANDARDS AND PROJECTED RESEARCH OBJECTIVES FOR LARGE FOSSIL-FUEL-FIRED BOILERS

	June 1979 NSPS	
	Lb NO_x/MBtu input to boiler[a]	NO_x ppm[b]
Gaseous fuel	0.2	150
Liquid fuel	0.3	225
Solid fuel	0.5 (subbituminous)	375
	0.6 (bituminous)	450

a. Expressed as NO_2.
b. Calculated at 3% excess O_2, dry basis.

NO_x FORMATION CHEMISTRY

For most combustion processes, particularly fossil-fuel combustion units, the only significant quantities of NO_x present in the flue gases are nitric oxide (NO) and nitrogen dioxide (NO_2) with NO usually representing 90% to

95% of the total NO_x from the combustion unit (7). Two separate mechanisms contribute to the formation of NO_x. One source, thermal NO_x, results from the oxidation of molecular nitrogen present in the combustion air, while the second source, fuel NO_x, results from the oxidation of nitrogen compounds released from coal (10). For a large coal-fired boiler, the fuel NO_x contribution may range from 30% to 80% of the total NO_x (15).

Thermal NO_x emission levels, as the name implies, are primarily dependent on the peak flame temperature generated by the burner and the residence time at that temperature. Therefore, a decrease in the peak flame temperature will decrease the thermal NO_x emissions. Principle reactions for the oxidation of molecular N_2 are as follows:

$$N_2 + O \rightarrow NO + N \qquad (1)$$

$$N + O_2 \rightarrow NO + O \qquad (2)$$

$$N + OH \rightarrow NO + H \qquad (3)$$

Unlike thermal NO_x, temperature has little effect on fuel NO_x. Fuel NO_x is dependent on the availability of O_2 in the flame. There are two competing reactions for the nitrogen containing compounds in the volatile flame region:

$$I + R \rightarrow NO + \ldots \qquad (4)$$

$$I + NO \rightarrow N_2 + \ldots \qquad (5)$$

Where I is a nitrogen containing intermediate and R is a hydrocarbon. Under fuel-rich conditions (high concentration of fuel in air) reaction (5) is dominant, resulting in lower NO_x concentrations; however, under fuel-lean conditions (low concentration of fuel in air) reaction (4) is dominant, resulting in higher NO_x concentrations.

NO_x formation is dependent on the combustion method, which varies with boiler design. The typical baseline NO_x emissions from different boiler types are shown in Figure 1.

STATUS OF TECHNOLOGY

Combustion modifications and FGT are the two basic types of NO_x control technology being developed for use with coal-fired boilers.

Combustion Modification

Combustion modification includes methods to inhibit the thermal and fuel NO_x formation. One combustion modification technique for reducing NO_x emissions is to increase the burner zone surface area. This was not developed as a control technique but as a method for reducing slagging in boilers. By increasing the burner zone surface area, the burner zone heat release rate

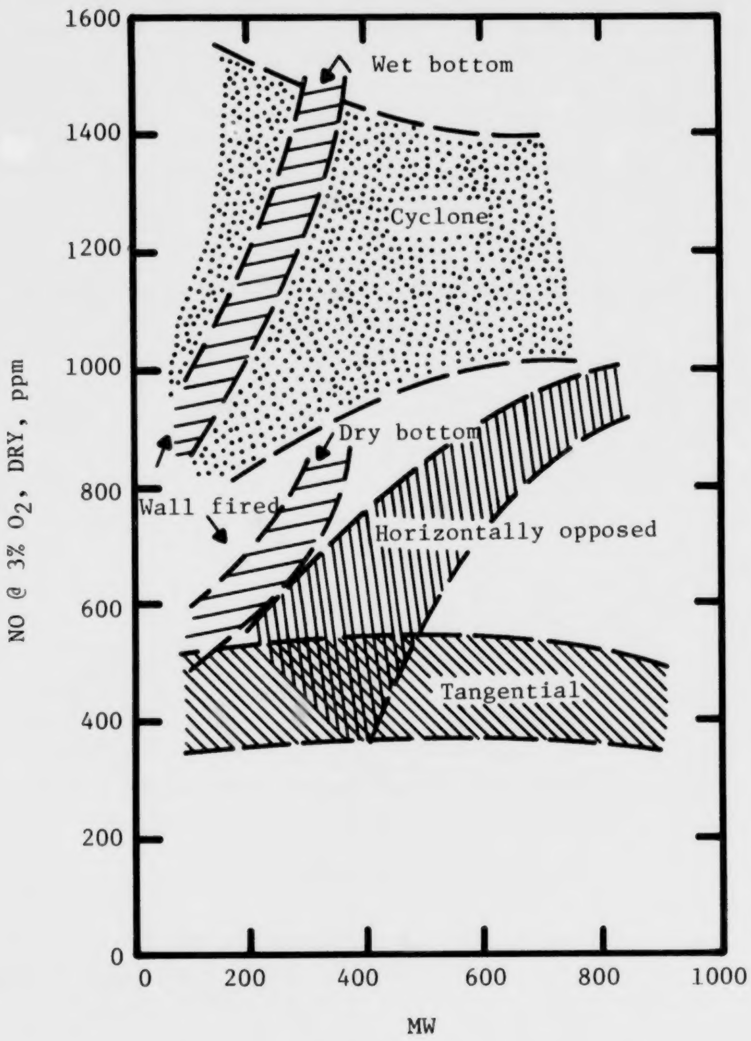

Figure 1. Baseline NO_x emissions - coal-fired utility boilers (23).

(defined as the heat input divided by the burner zone surface area) was decreased. NO_x emissions decreased as a result because gas temperatures were lowered by the increased heat removal capacity. The larger boiler also proved valuable as lower turbulence burners, such as the low-NO_x burner, were developed because the increased size allows longer residence times to complete carbon burnout. Commercial acceptance for reduced burner zone heat release rates came about in the 1970's. Figure 2 shows burner zone heat release rates for pulverized-coal-fired boilers ordered before and after 1970.

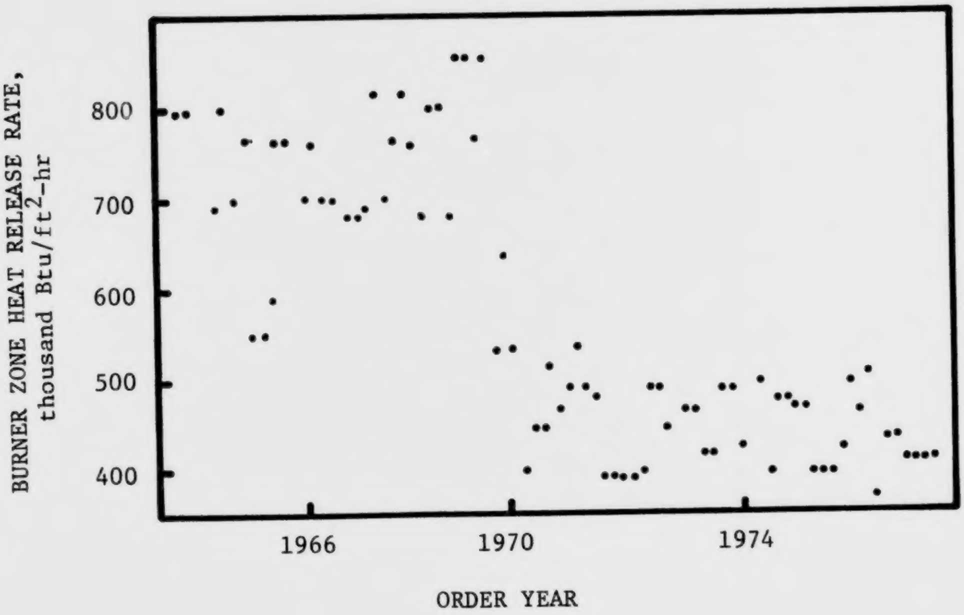

Figure 2. Pulverized-coal-fired boiler burner zone heat release rates (11).

Another combustion modification method is flue gas recirculation. Flue gas is extracted at the economizer outlet and returned to the furnace. The cooled flue gas lowers the overall temperature of the gas inside the furnace and reduces the oxygen concentration. Flue gas recirculation works well for oil and gas but has not been proven effective for coal.

Overfire air, unlike the above two techniques, which primarily lower burner zone temperatures, is designed to limit oxygen availability at the flame. Air ports are installed above the burner zone to inject a portion of the combustion air. The burners are thus fired more fuel rich than normal. Fuel-rich conditions decrease fuel NO_x formation. (This method maintains the burner zone in a reducing atmosphere with an oxidizing atmosphere above the flame region. This reducing atmosphere is a more corrosive environment for the boiler walls.)

A technique similar to overfire air is burners out of service. Instead of placing air ports in the boiler wall, individual burners or rows of burners admit only air. The remaining burners make up the difference by firing additional coal if pulverizer capacity is available. As in overfire air, the active burners operate at more fuel-rich conditions than normal. This technique was developed primarily for retrofit applications.

Another technique to minimize oxygen availability is low excess air. In this technique, sufficient air is admitted to the boiler to complete combustion but is minimized to reduce NO_x formation.

Although NO_x control could be obtained by these boiler modifications, work was continued by boiler manufacturers and others to obtain lower levels of NO_x emission and to avoid operational problems such as corrosion, erosion, combustion instability, and energy penalties from some of the methods.

Babcock & Wilcox, Inc., (B&W) developed their dual register burner to meet 1971 NSPS (0.7 lb NO_2/MBtu); however, test on pulverized coal units demonstrated that the 0.6 lb NO_2/MBtu level could also be obtained (3). The dual register burner features limited turbulence, conical diffuser mixing, and secondary air introduced around the primary air nozzle in two concentric air zones that are independently controlled. Air flow to the burners is controlled by use of a compartmented windbox.

A series of burners has been developed by the Foster Wheeler Energy Corporation for NO_x control. The latest is the controlled-flow/split-flame burner (30, 31). This burner uses dual registers on the secondary air to produce a substoichiometric air zone near the flame. A modified annular primary air nozzle is also used to separate the coal-air mixture into four concentrated streams that form four independent flames. Overfire air can be used with the controlled-flow/split-flame burner for additional NO_x control but it is not recommended.

NO_x control is being accomplished by the Riley Stoker Corporation using a controlled diffusion flame and the Turbo® furnace (21). The Turbo furnace is designed with a venturi shaped bottom to utilize the lower furnace cooling surface more effectively. Combined with the Turbo furnace, downward-tilted, nonswirl burners are used to delay mixing of the secondary air with the fuel and primary air. In this way the fuel and secondary air mix by diffusion, which decreases the combustion rate and flame temperature.

Combustion Engineering, Inc., produces tangentially fired boilers, in which the burners are directed tangent to an imaginary circle at the center of the furnace. This provides a large amount of internal recirculation of the combustion gases and slower mixing of fuel and air (16). These boilers are inherently low in NO_x formation. Additional reduction in emission levels can be achieved using overfire air.

These combustion modification techniques are described in greater detail in other literature (14, 15, and 23).

Flue Gas Treatment

The FGT methods of NO_x control applicable to coal-fired utility boilers are well described in literature (1, 9, and 13). These postcombustion processes can be divided into dry or wet types. The dry processes can be further categorized into four subdivisions: catalytic reduction, noncatalytic reduction, adsorption, and irradiation. The majority of the dry processes are of the reduction type. These catalytic and noncatalytic reduction processes can also be classified as selective or nonselective processes based on the type of reducing agent used. The majority are selective and usually use NH_3 as the reducing agent. If the NH_3 is injected after the boiler economizer, where temperature of the flue gas is about 700°F to 800°F, a catalyst is necessary. These processes are described as SCR processes. If NH_3 is injected into the secondary superheater region of the boiler, where temperature of the flue gas is 1,000°F to 1,800°F, a catalyst is not necessary. These processes are described as SNR processes.

Selective Catalytic Reduction--

The SCR method is the most advanced FGT method, and the one on which the overwhelming majority of NO_x FGT processes are based. As with the majority of all types of NO_x FGT, most of the SCR processes were developed in Japan. Since the presence of some oxygen improves the NO_x reduction, the reactions of NH_3 with NO_x may best be expressed as follows:

$$4NH_3 + 4NO + O_2 \rightarrow 4N_2 + 6H_2O \qquad (1)$$

$$4NH_3 + 2NO_2 + O_2 \rightarrow 3N_2 + 6H_2O \qquad (2)$$

In the presence of a catalyst and with the optimum reaction temperature, usually 570°F to 840°F, an NH_3:NO molar ratio of 1:1 typically reduces NO_x emissions by 90% with residual NH_3 concentrations of 10 to 20 ppm or higher. It should be noted that the Japanese seem to prefer 80% NO_x removal in which NH_3:NO molar ratios range from 0.81:1 to 0.9:1 with residual NH_3 concentration usually less than 5 ppm. (This reduces capital and operating costs as well as effects on downstream equipment from ammonium salt deposition.)

The only equipment necessary is an NH_3 storage and injection system, a reactor, and catalyst. Additional fan capacity is necessary because of the pressure drop increase across the reactor of 2 to 5 in. H_2O (4 to 9 mm Hg).

The components and precise composition of most catalysts are proprietary. However, catalysts composed mostly of titanium and vanadium oxides are generally used, since these components are resistant to attack by SO_2 and SO_3. SO_2 oxidation to SO_3 can be a problem, especially with coal-fired boilers where flue gas SO_2 concentrations are relatively high. Proprietary additives to the catalyst can reduce the amount of SO_2 oxidation to less than 0.5% to 1.5%.

In addition to the different catalyst compositions, different reactor and catalyst configurations have also been developed, primarily to handle various particulate loadings. With natural-gas-fired boilers, fixed packed-bed reactors with spherical-, cylindrical-, or ring-shaped catalyst pellets are used. Parallel flow reactors and catalysts are preferred for oil- and coal-fired boilers to tolerate the particulate matter in the flue gas stream. Parallel flow designs include tubular, honeycomb, corrugated, or parallel-passage configurations. The catalyst may be an active material coated on a metallic or ceramic carrier or may be a homogeneous material.

The major concerns of operating SCR processes include: plugging and erosion of the catalyst by fly ash; emission of NH_3 or ammonium salts; increased SO_3 emissions from oxidation of SO_2; effects on operation of downstream equipment such as the air heater, electrostatic precipitator (ESP), flue gas desulfurization (FGD) process, and baghouse; environmentally sound disposal or reclamation of catalyst; lack of proven NH_3 analytical control systems; sensitivity of the process to temperature changes due to boiler load variations; and reliability of the process and its effects on the boiler system availability.

In spite of the potential problems, there are over 60 full-scale SCR units successfully operating on gas- or oil-fired boilers in Japan. Over 10% of these units are larger than 330 MW. Two commercial SCR units began operating in 1980 on coal-fired boilers in Japan. The 175-MW retrofit unit supplied by Mitsubishi Heavy Industries at the Shimonoseki Station of Chugoku Electric Power Company was the world's first full-scale coal-fired SCR system. It began operation in April 1980 and is operating at its designed 51% NO_x reduction efficiency with less than 1 ppm NH_3 slip. The other SCR unit is 90-MW capacity on a new 350-MW boiler at Tomakomai Station of Hakkaido Electric Power Company. It was supplied by Babcock-Hitachi and began operation in October 1980. Two other SCR units on coal-fired boilers are under construction with planned startup by mid-1981.

In the United States, EPA and the Electric Power Research Institute (EPRI) are evaluating SCR technology on coal-fired pilot-scale units. EPA sponsored two 0.5-MW-size tests, each of which was recently concluded. The UOP Shell Flue Gas Treatment process for simultaneous NO_x and SO_x control was evaluated at Tampa Electric Company's Big Bend Station. The Hitachi Zosen SCR process was tested at the Plant Mitchell Station of Georgia Power Company. EPRI is currently operating a 2.5-MW pilot plant at the Arapahoe Station of Public Service Company of Colorado using the Kawasaki Heavy Industries, Ltd., process.

The first large-scale SCR demonstration unit in the United States is being erected by Southern California Edision Company at the Huntington Beach Station. It is a 107.5-MW capacity on a gas- and oil-fired unit.

Selective Noncatalytic Reduction—

Exxon Research and Engineering Corporation developed the SNR process in which NH_3 is injected into the boiler where proper flue gas temperatures allow the reduction of NO_x by reaction with NH_3 to proceed without a catalyst. Generally, 40% to 60% NO_x reduction is achieved with $NH_3{:}NO_x$

molar ratios of 1 to 2:1. SNR may be more attractive than SCR in cases where only 40% to 60% NO_x control is needed since SNR is simple and does not require expensive catalysts.

The general disadvantage of SNR is the limited NO_x control achievable, especially with large boilers, due to the difficulty of achieving rapid uniform mixing and the variations of flue gas temperature and composition usually present within the boiler region where the SNR is operated. NH_3 consumption and unreacted NH_3 levels can also be high.

There are several large SNR units installed in Japan, between 30- and 100-MW capacity, mostly supplied by Tonen Technology (a subsidiary of Toa Nenryo) which has a license from Exxon. These are operated on gas- and oil-fired boilers or furnaces. Practically all are only for emergency use during a photochemical smog alert or when total plant emissions exceed the regulation.

There are presently two commercial SNR plants operating in the United States. One is on a glass melting furnace and the other a petroleum refinery, both located in California. The construction of five other industrial-scale units is planned. The SNR process is also being installed by Exxon at the No. 4 oil-fired unit of the Haynes Station of the Los Angeles Department of Water and Power.

Other Flue Gas Treatment Techniques--

In addition to SCR and SNR, dry processes which are being developed for simultaneous SO_x and NO_x control include:

1. Activated carbon processes where NH_3 reduces NO_x to N_2.

2. Copper oxide processes where NH_3 reduces NO_x to N_2.

3. Electron beam irradiation processes in which NH_3 is added to produce ammonium sulfate and nitrate.

The optimum temperature range for simultaneous SO_x and NO_x control with activated carbon processes is 430°F to 445°F. Although NO_x may be adsorbed below 212°F, for treating large quantities of flue gas above 212°F the carbon is mainly useful as an NO_x reduction catalyst. Therefore, while NO_x is converted to N_2 by reaction with NH_3 in the presence of the activated carbon catalyst, SO_2 is simultaneously adsorbed by the carbon to form H_2SO_4. The H_2SO_4 may also compete for NH_3 in forming ammonium sulfate or bisulfate. The formation of these ammonium salts increases NH_3 consumption and also lowers catalyst activity. The carbon must be regenerated, either by washing or thermal regeneration. Washing produces a dilute solution, which requires much energy to concentrate for use as a fertilizer. Thermal regeneration seems to be preferred. A concentrated SO_2 gas is recovered, which can be used for sulfuric acid or elemental sulfur production.

The major drawback of the activated carbon processes is the enormous consumption of activated carbon, which is more expensive than ordinary carbon used only for SO_x removal. Since carbon and ammonia consumption increases with the SO_2 content of the flue gas, the process is best suited for flue gases relatively low in SO_2. In Japan, Sumitomo Heavy Industries and Unitika Company have operated activated carbon pilot plants of 0.6-MW and 1.5-MW capacity respectively.

The UOP Shell Flue Gas Treatment process may simultaneously remove SO_x and NO_x. SO_x reacts with the copper oxide acceptor to form copper sulfate. The copper sulfate and copper oxide are SCR catalysts for the NO_x reduction by NH_3. Regeneration of the multiple catalyst beds by a reducing gas, such as H_2, yields a SO_2-rich stream that can be used to produce liquid SO_2, elemental sulfur, or sulfuric acid. By eliminating NH_3 injection, the process is strictly an FGD process, whereas, eliminating regeneration of the catalyst beds allows the process to be used for only NO_x control. The major disadvantages are the large consumption of fuel for making hydrogen and the catalyst expense.

In addition to the EPA-sponsored pilot plant mentioned earlier, the process has been installed in Japan on a 40-MW oil-fired boiler. The unit has demonstrated 90% SO_x removal and 70% NO_x reduction.

Another process for simultaneous SO_x and NO_x control is the electron beam process developed by Ebara Manufacturing Company in Japan. NH_3 is added to the flue gas, after which the gas stream is irradiated with an electron beam in a reactor, promoting the conversion of SO_x, NO_x, and NH_3 to ammonium sulfate and ammonium nitrate. The ammonium sulfate and ammonium nitrate may be collected downstream in an ESP or baghouse and potentially sold as a fertilizer. The most economically practical removal efficiency range appears to be 80% to 90% for each of NO_x and SO_x, though higher removals can be achieved with much greater electron beam energy input. The optimum temperature range is 160^oF to 195^oF.

Ebara has worked on the process since 1971. It has been tested at a 0.3-MW and 3-MW scale in Japan. Avco Corporation in the United States has also examined this technique and has a cross-licensing agreement with Ebara in sharing of technology and in marketing of the process. Although the process appears attractive because of simplicity, simultaneous SO_x and NO_x control, and byproduct formation, there are still many questions concerning costs, byproduct quality, etc., which must be determined.

The wet processes normally involve simultaneous removal of SO_x and NO_x. The major problem associated with wet NO_x control processes is the absorption of NO_x by the scrubbing solution in which it can be concentrated and converted into other forms. NO_x in the flue gas is predominantly NO, which is much less soluble than NO_2, whereas, NO_2 is even less soluble than SO_2. The two common methods of removing the NO_x in flue gas by wet processes are: (1) direct absorption of the NO_x in the absorbing solution or (2) gas-phase oxidation to convert the relatively insoluble NO to NO_2, followed by absorption of NO_2. Presently, development of the wet NO_x FGT processes has practically ceased because of the complexity and unfavorable economics of these processes in comparison with the dry processes.

STATUS OF PROCESSES EVALUATED

ADVANCED LOW-NO_x BURNER

EPA instituted a program to develop a coal-firing burner capable of reducing NO_x formation to levels lower than achieved by present combustion modifications. This program is directed toward developing burner prototypes for industrial and utility appplication. The burner design at various stages of development is shown in Figure 3. Only the utility ALNB prototype development program is discussed in detail in this report.

Process Description

The ALNB is being designed to prevent the formation of both types of NO_x (thermal and fuel) while maintaining boiler efficiency and meeting boiler demand. The primary objectives are: (1) to provide an initial fuel-rich, i.e., oxygen deficient, zone which maximizes the conversion of organic nitrogen compounds to N_2, and (2) create an overall oxidizing atmosphere around the fuel-rich zone to maximize burnout and to minimize the potential for corrosion in the lower furnace section of the boiler. These objectives are obtained by providing for the optimum interaction between the primary fuel jet and the swirl-stabilized recirculation zone, together with delayed air addition from the outboard staged air injectors (33).

For this study the ALNB concept was integrated into a B&W dual register burner design with four tertiary air ports located a distance of about one throat diameter around the central burner (3). Air admitted through the burner is made up of three air streams referred to as primary, inner, and outer secondary air. Primary air is used as the medium to carry the entrained pulverized coal. Secondary air is injected around the primary air through an annulus. Swirl vanes in the inner secondary air annulus impart swirl to control mixing of the primary and inner secondary streams and to control flame shape. The remaining secondary air is admitted through the outer secondary air annulus, which is concentric to the inner secondary air annulus. Two possible configurations for the tertiary air ports are shown in Figure 4. The first has four ports per burner, the second shares ports between burners. The ports are arranged to provide specific mixing rates with the other air streams and avoid fuel-rich zones along the lower furnace wall. The central burner is designed to operate at approximately 70% stoichiometry to minimize oxygen availability for conversion of fuel nitrogen to NO_x and the remaining 45% to 50% of the air is supplied through the tertiary ports to complete combustion.

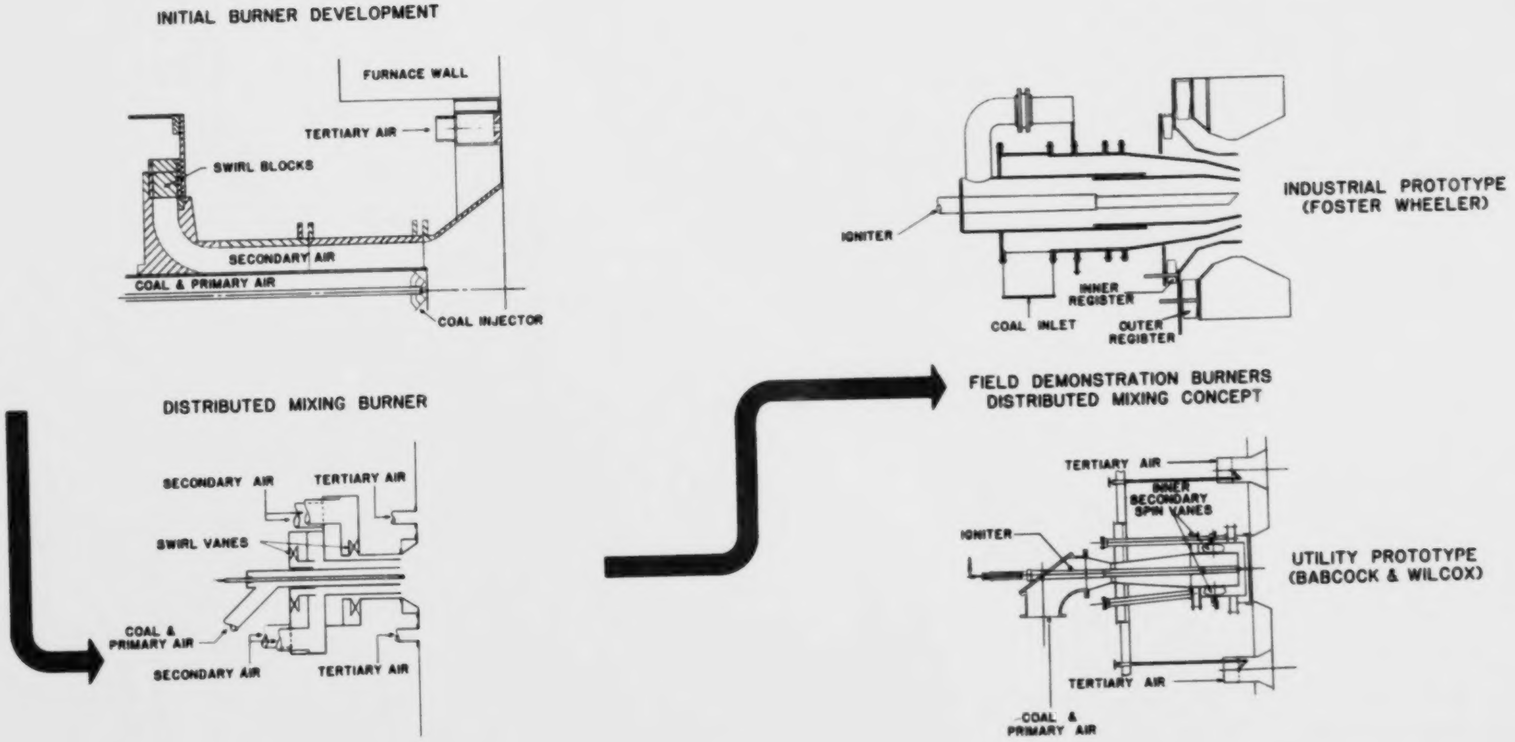
INITIAL BURNER DEVELOPMENT
FURNACE WALL
TERTIARY AIR
SWIRL BLOCKS
SECONDARY AIR
COAL & PRIMARY AIR
COAL INJECTOR
DISTRIBUTED MIXING BURNER
SECONDARY AIR
TERTIARY AIR
SWIRL VANES
COAL & PRIMARY AIR
SECONDARY AIR
TERTIARY AIR
IGNITER
INNER REGISTER
COAL INLET
OUTER REGISTER
INDUSTRIAL PROTOTYPE (FOSTER WHEELER)
FIELD DEMONSTRATION BURNERS DISTRIBUTED MIXING CONCEPT
TERTIARY AIR
INNER SECONDARY SPIN VANES
IGNITER
UTILITY PROTOTYPE (BABCOCK & WILCOX)
TERTIARY AIR
COAL & PRIMARY AIR

Figure 3. Major stages of the ALNB development (11).

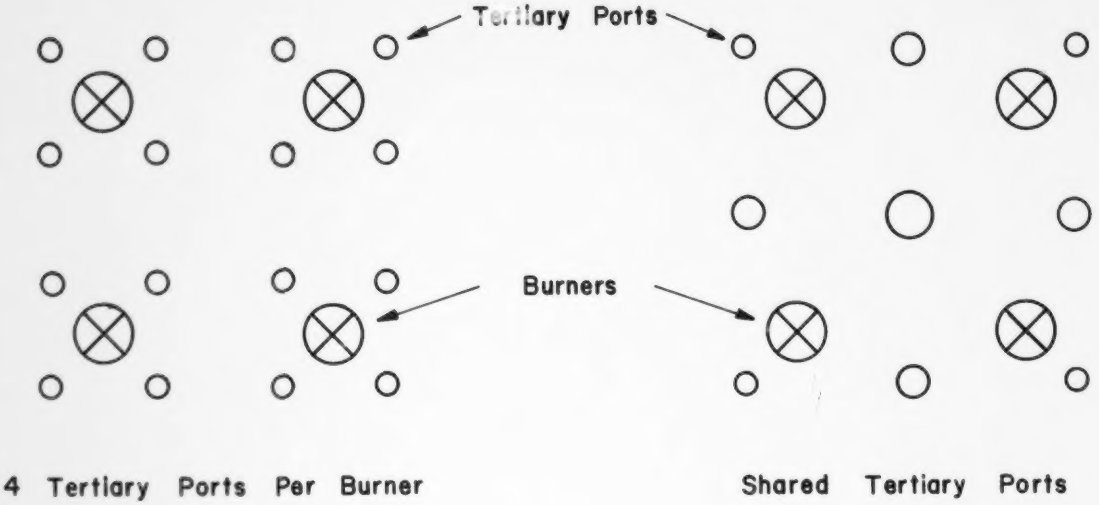

Figure 4. Alternatives for injection of ALNB tertiary air.

At the time of the writing of this report, not all areas of the ALNB design had been defined. However, the general description given above is expected to be the basis for prototype construction. The research goal for the NO_x emission level from the ALNB is 0.2 lb NO_2/MBtu.

Technical Considerations

In a study funded by EPA (18, 33) the effects of various burner and operating variables on NO_x emissions were explored by EERC. Both single and multiple burner tests were performed and the results quantified to aid in burner development.

Results of the test on one burner evaluated in the single burner test program are shown in Figures 5, 6, and 7. The optimum operating conditions for this burner are a burner zone stoichiometric ratio (SR_B) of 0.5 to 0.7, a primary swirl vane angle (S_P) of 45 degrees, and a secondary swirl vane angle (S_S) of 60 degrees. These data were obtained at a primary stoichiometric ratio (SR_P) of 0.23 and 0.25 and a theoretical stoichiometric ratio (SR_T) of 1.25. These results are unique to a particular design because optimum operating conditions will vary as burner design varies.

Mutiple burner test results summarized in Figure 8 show that lower NO_x emissions are directly related to burner zone stoichiometry. The burner zone stoichiometry used must be weighed against the CO level (combustion

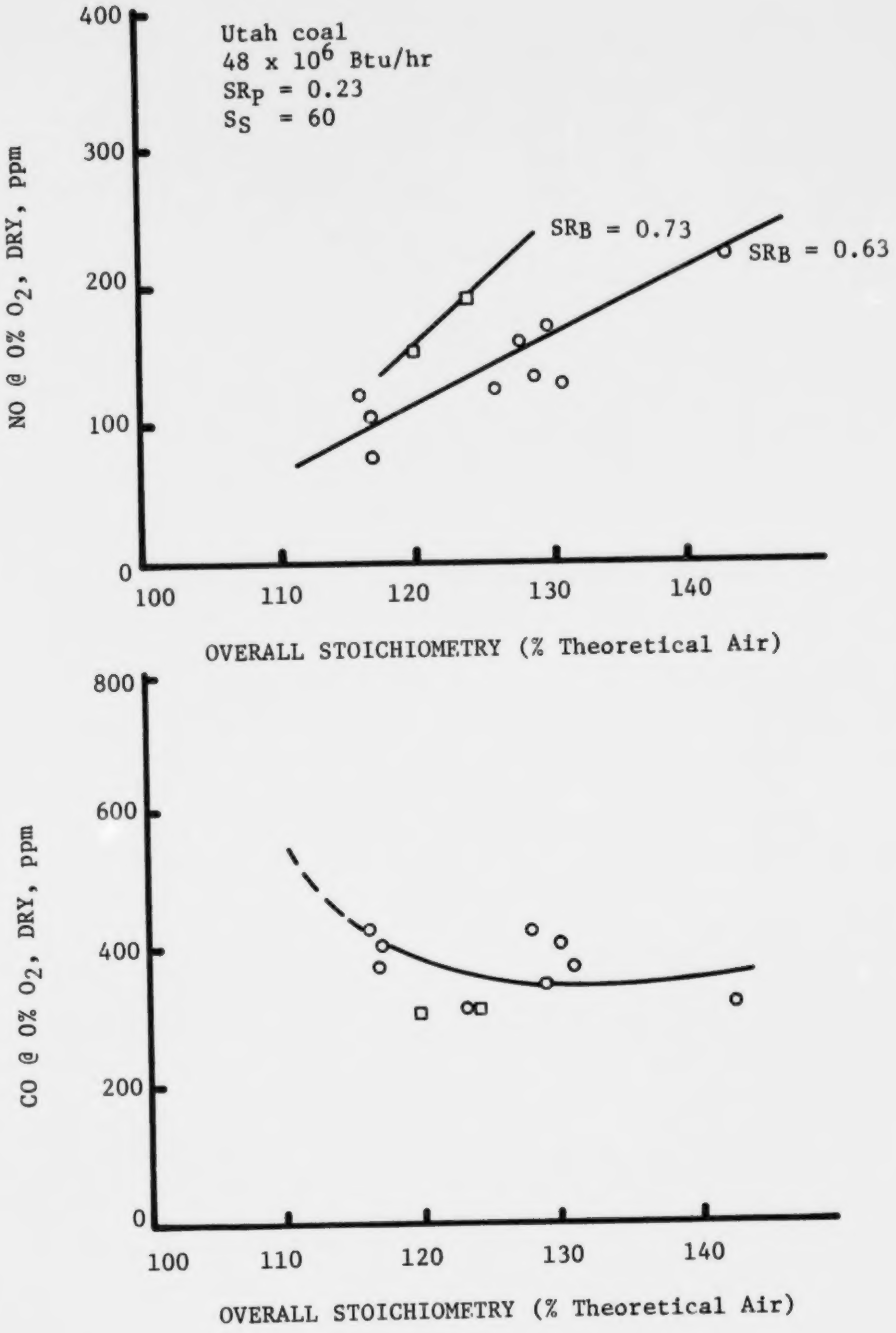

Figure 5. Effects of ALNB burner zone stoichiometry, single burner (11).

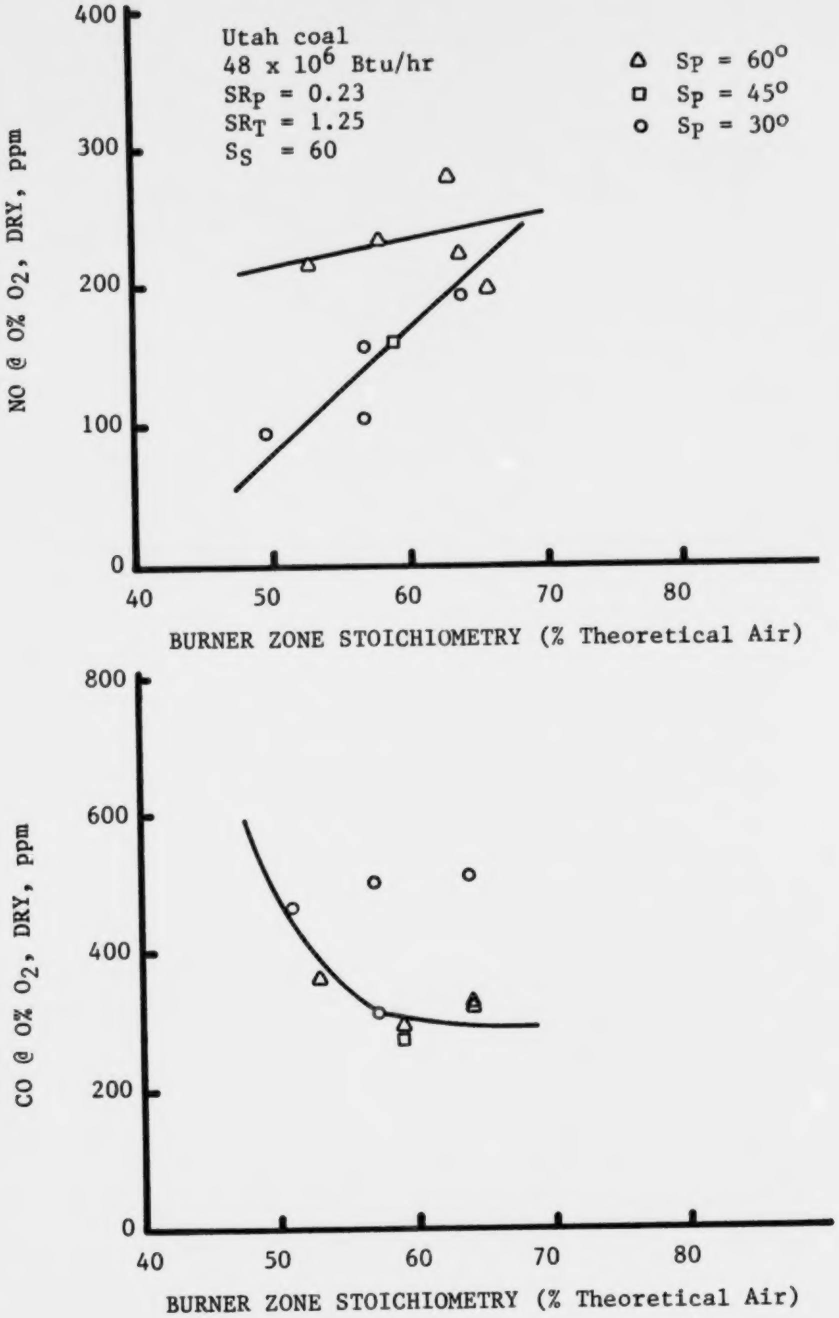

Figure 6. Effects of ALNB primary swirl, single burner (11).

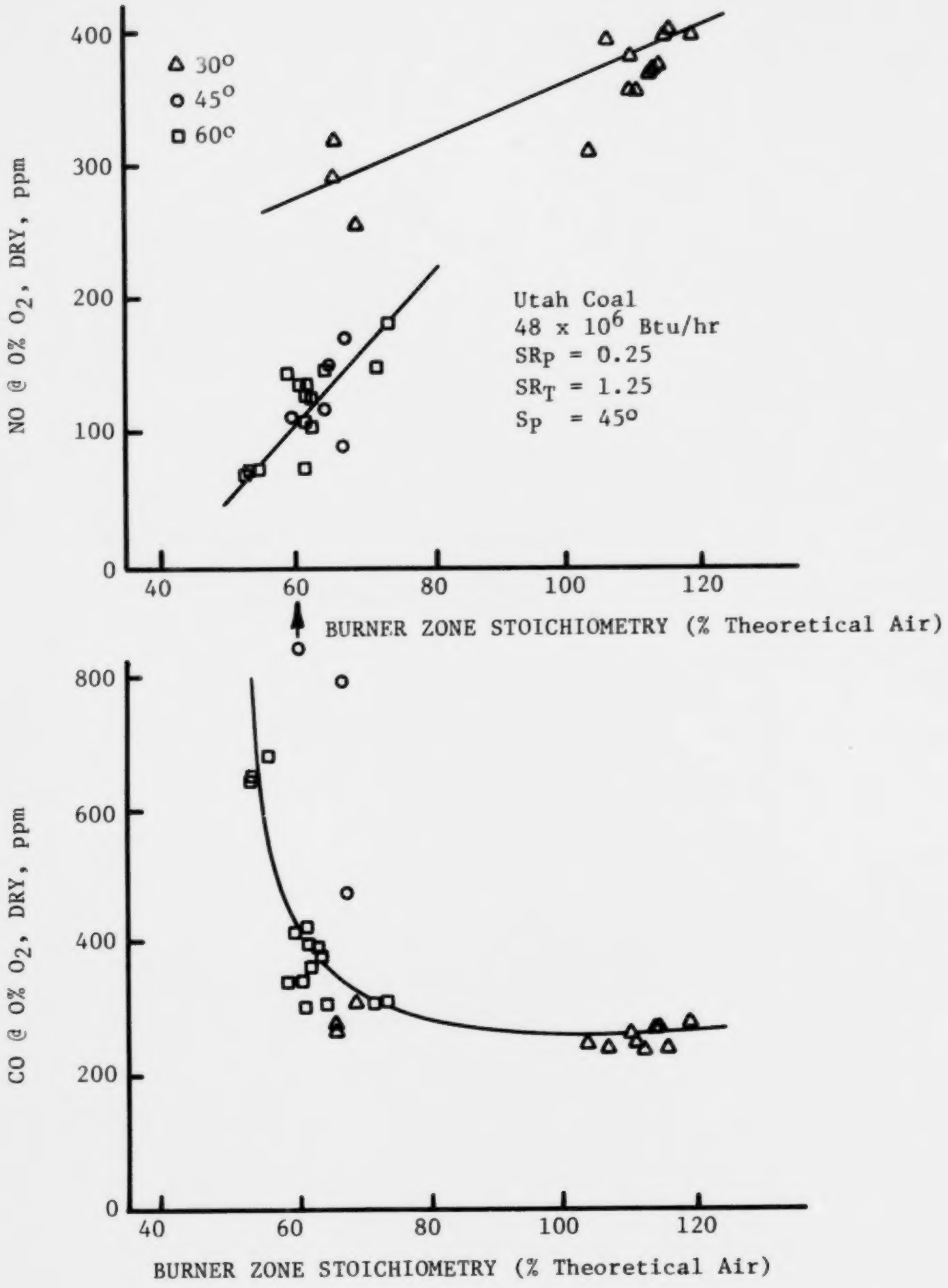

Figure 7. Effects of ALNB secondary swirl, single burner (11).

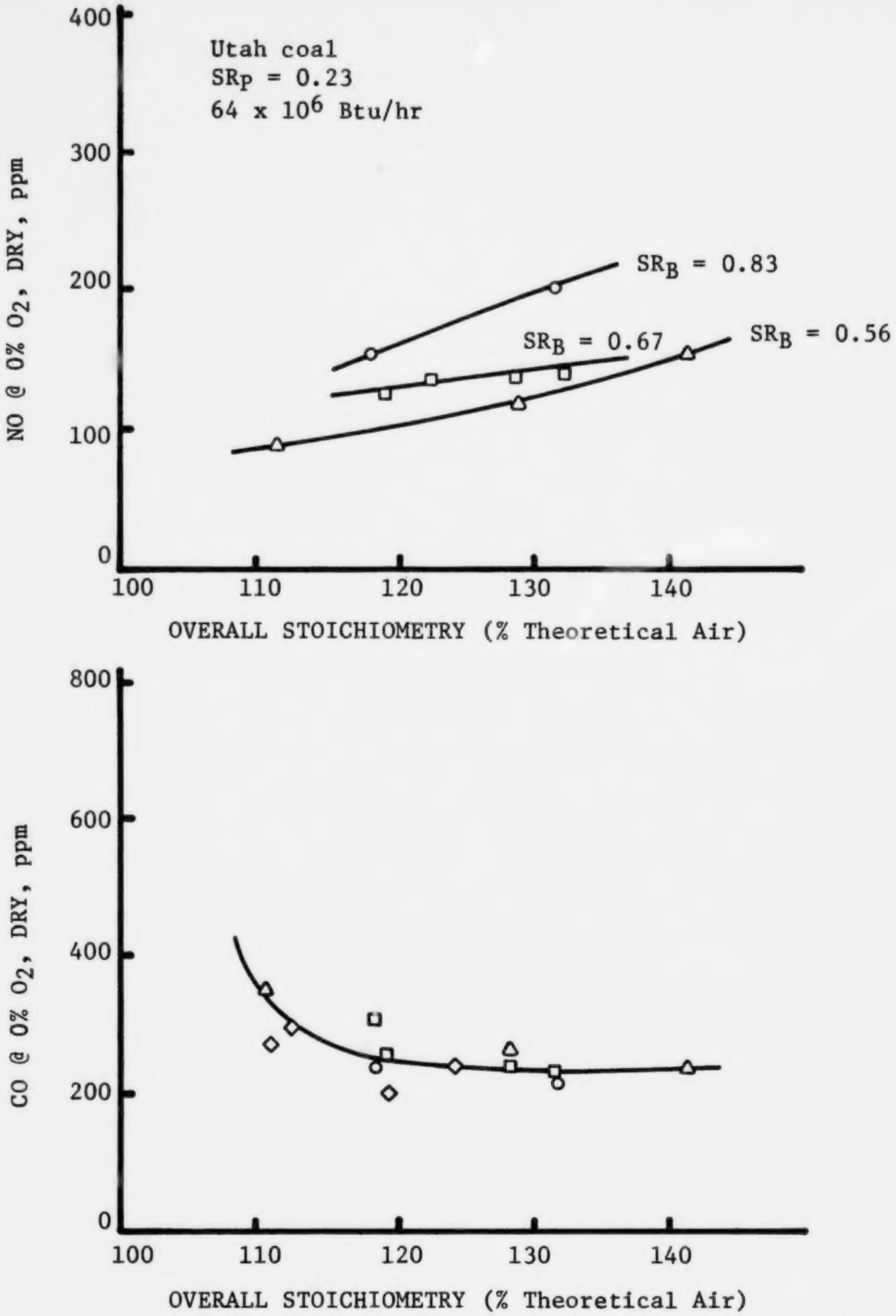

Figure 8. Effects of ALNB burner zone stoichiometry, four burners fired at 12.5 x 10^6 Btu/hr each (11).

efficiency). Also studied in the multiple burner tests was the effect of removing rows or columns of tertiary air ports from service, as shown in Figure 9. Results showed that NO emission decreased slightly but carbon burnout (CO level) was more sensitive. Additional optimization is required.

A study by EERC on the effects of coal type was initiated to develop a data bank on a full range of U.S. coals. Results from this study, of which Figure 10 is an example, led to the conclusions that NO_x emissions are sensitive to fuel type, that the nitrogen content of the fuel does not correlate with NO_x emissions, and that burner efficiency is sensitive to the type of coal.

Development Status

The first phase of low-NO_x burner development by EPA was initiated in 1970 when EPA contracted with the International Flame Research Foundation (IFRF) to study the influence of burner variables on NO_x emissions using pulverized coal. In the IFRF study the following burner parameters were investigated:

- Method of fuel injection
- Throat velocity
- Geometry of the burner exit
- Position of the fuel injector
- Type of burner exit
- Proportion of primary air
- Swirl intensity of the combustion air

Results of the study show the two variables having the greatest effect on NO_x emissions to be the method of fuel injection and the degree of swirl. Test work was performed on a 2 to 3 thermal MW ($6-9 \times 10^6$ Btu/hr) refractory tunnel.

To obtain burner data at a more realistic boiler size and firing rate, scaleup was performed by EERC on a boiler and a large water tube simulator capable of firing up to 40 thermal MW with single or multiple burners. A smaller system simulating a D-type package water tube boiler was used to evaluate various burner designs.

While the test program of IFRF was designed to determine the effect of various burner parameters on NO_x emissions, the EERC program was designed to quantify these effects for development of an experimental burner and boiler system. The EERC program thus had a larger scope than the IFRF program, covering not only single burner variables at greater firing rates, but also

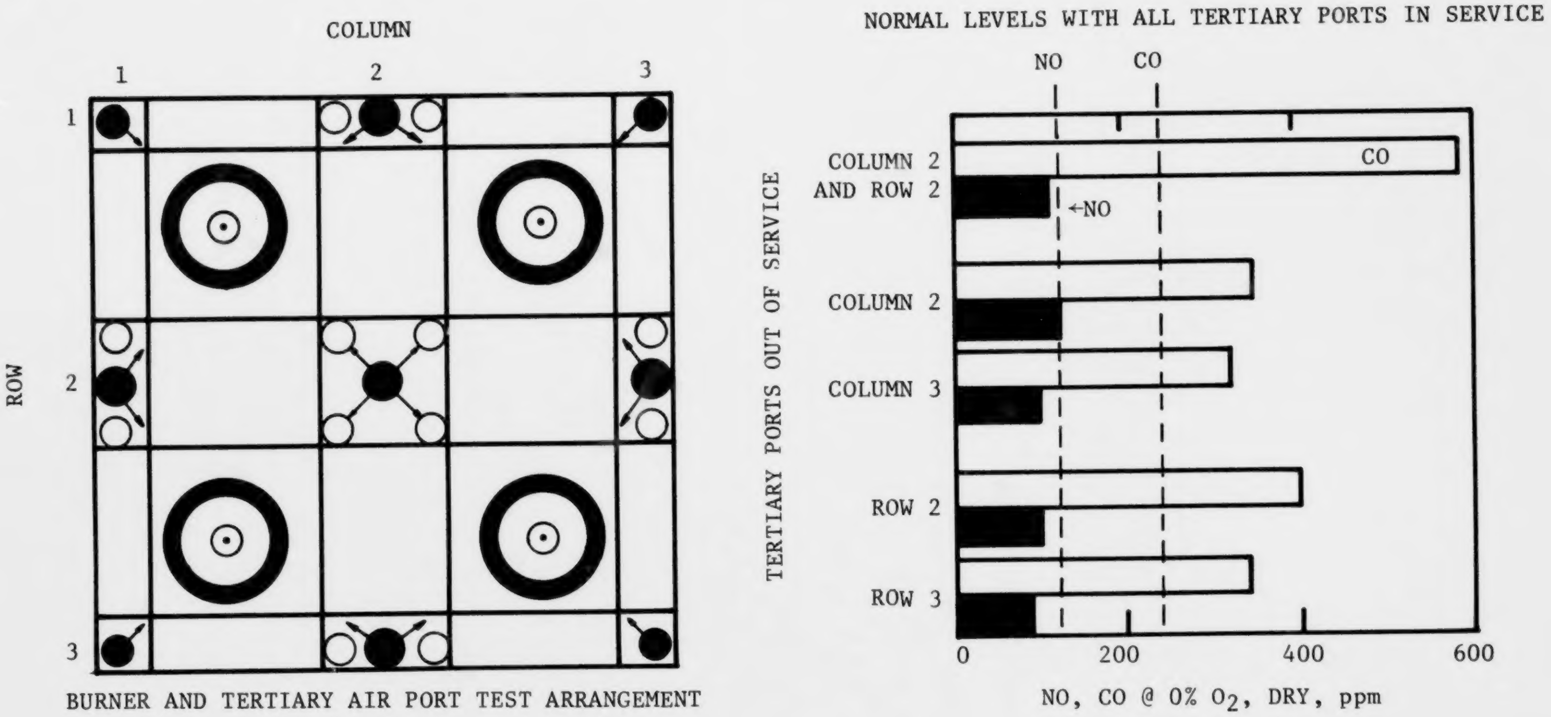

Figure 9. Effects of ALNB tertiary ports out of service, four burners fired at 12.5 x 10^6 Btu/hr each (11).

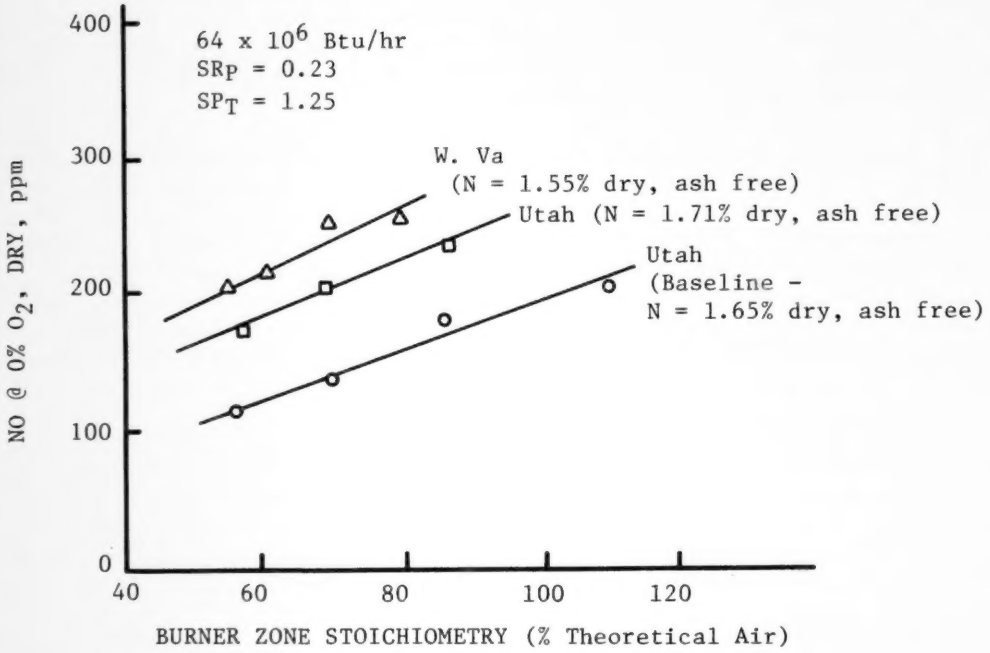

Figure 10. Effects of ALNB coal type, four burners fired at 12.5×10^6 Btu/hr each (11).

the interactions of multiple burners and the effects of coal types. Figure 11 shows one of the burners used in the test program, called the simple double concentric burner, and the variables evaluated. Tertiary air was used with the simple double concentric burner and other burners used in the test program.

While the EERC test program was being conducted, another possible use for the low-NO_x burner was being studied at a pilot-plant scale by EPA (17). This study was exploring sulfur capture using a dry sorbent. It is hypothesized that after coal and sorbent are mixed in the pulverizer to achieve intimate contact, the ALNB burner will create conditions (fuel-rich burner zone and decreased peak flame temperature) that will be favorable for SO_x removal. Dry sorbents that have been tested are limestone, Na_2CO_3, and $NaHCO_3$. Depending on pilot-plant results, funding will be sought for field evaluation of dry sorbents. The stated goals are to obtain 50% SO_2 capture at a 2:1 sorbent:SO_2 stoichiometry and a research goal of 90% SO_2 removal at 3:1 sorbent:SO_2 stoichiometry.

Upon completion of the ALNB design, EPA contracted with B&W to perform a field evaluation of the burner in a utility boiler. EERC has received the subcontract. The industrial boiler contract which parallels the utility program was awarded to EERC with the subcontract to Foster Wheeler. The nine major task areas that make up the utility boiler field evaluation program are (1) program definition, (2) prototype construction and performance evaluation, (3) host-site boiler baseline evaluation, (4) burner installation, (5) performance optimization, (6) industry coordination, (7) boiler restoration, (8) data analysis, and (9) summary of program results (4, 18).

The field evaluation program is behind schedule because of delays in obtaining an acceptable host site. Some boilers were omitted as possible host sites because more spacing between burners was required for the addition of tertiary ports than was available while others required major changes to the windbox and boiler structural supports. Further delays resulted from an unwillingness to participate by owners of possible host sites (4).

This program should provide information on areas of uncertainty such as the effect of commercial application of the ALNB on boiler tube bending and configuration, boiler wall structural requirements, and boiler efficiency.

EXXON PROCESS

Process Description

The Exxon process, developed by Exxon Research and Engineering Company, controls NO_x from flue gas by injection of NH_3 and air through a distribution grid, or grids, directly into the cavity of the secondary superheater (29).

At high temperatures, NO_x reacts with NH_3 in the presence of oxygen (O_2) by the following overall reaction (28):

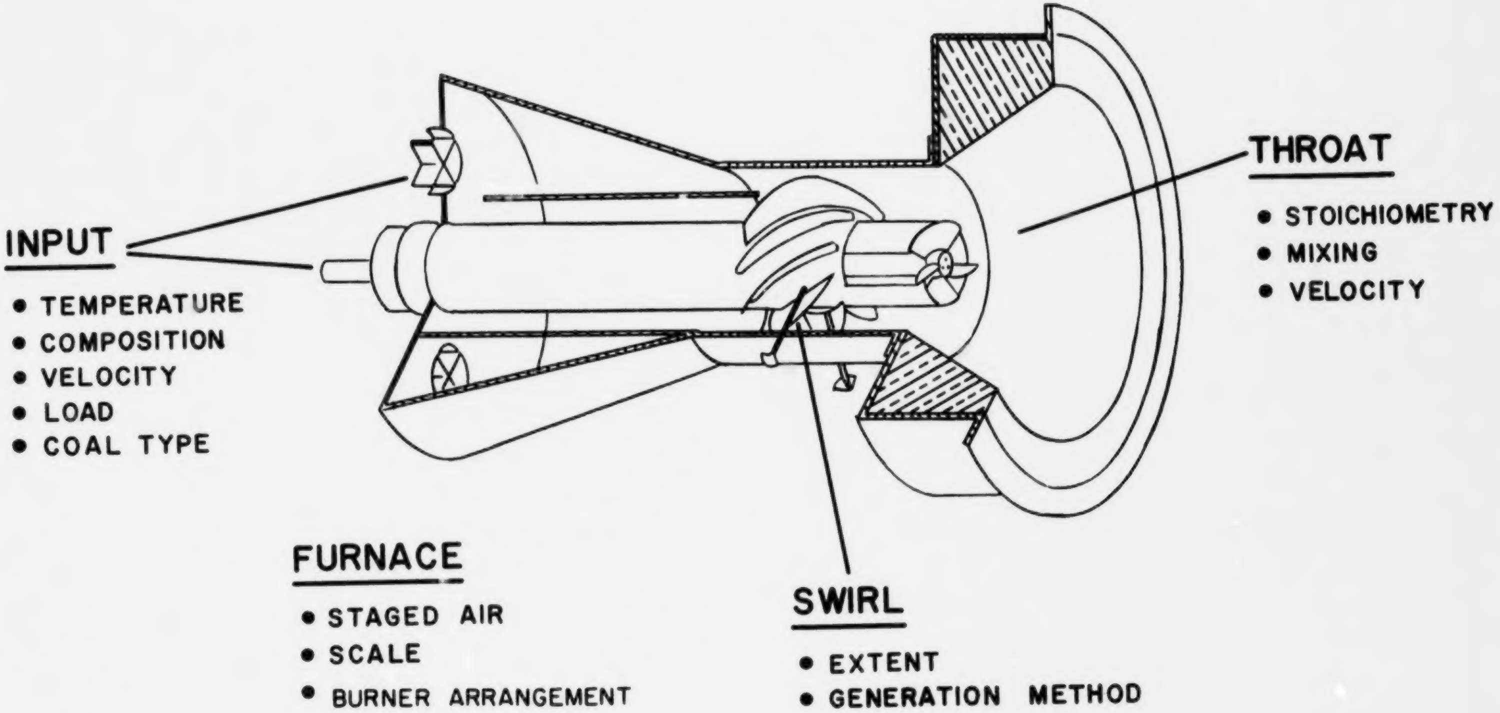
INPUT
• TEMPERATURE
• COMPOSITION
• VELOCITY
• LOAD
• COAL TYPE
FURNACE
• STAGED AIR
• SCALE
• BURNER ARRANGEMENT
SWIRL
• EXTENT
• GENERATION METHOD
THROAT
• STOICHIOMETRY
• MIXING
• VELOCITY

Figure 11. Variables evaluated in the single ALNB test program (11).

$$NO + NH_3 + 1/4O_2 \rightarrow N_2 + 3/2H_2O \qquad (1)$$

R. K. Lyon of Exxon Research (28) has proposed the following mechanism for this reaction:

$$NH_2 + NO \rightarrow N_2 + H + OH \qquad (2)$$

$$NH_2 + NO \rightarrow N_2 + H_2O \qquad (3)$$

$$H + O_2 \rightarrow OH + O \qquad (4)$$

$$O + NH_3 \rightarrow OH + NH_2 \qquad (5)$$

$$OH + NH_3 \rightarrow H_2O + NH_2 \qquad (6)$$

$$H + NH_3 \rightarrow H_2 + NH_2 \qquad (7)$$

This reaction proceeds at a satisfactory rate in a narrow temperature range around 1,740°F (950°C) as shown in Figures 12 and 13. Below 1,650°F (900°C), the reaction rate is too slow for adequate NO_x control, causing NH_3 and NO to flow through unreacted. Above 1,830°F (1,000°C), the NH_3 reacts with O_2 to produce NO_x, as illustrated by the reaction:

$$NH_3 + 5/4O_2 \rightarrow NO + 3/2H_2O \qquad (8)$$

Because of this sensitivity, temperature gradients within the boiler reaction zone caused by variable heat transfer and gas velocity or changes in the boiler load have considerable effect on the process efficiency.

Residence time is as important as reaction temperature. The reactants (NO, NH_3, O_2) must remain in the boiler injection zone for a sufficient length of time for the reaction to go to the desired completion. A typical residence time is 0.1 second.

Proper mixing of the reactants with the flue gas is crucial. Uneven distribution can cause pockets of ammonia as well as NO_x to pass through the boiler unreacted. The Exxon process uses proprietary Exxon gas-phase mixing technology to disperse the small volume of reactants throughout the flue gas.

Ammonia addition is dependent on the NO_x concentration in the flue gas. Tests at optimum temperature conditions indicate that a rate of 0.6 to 2 moles of NH_3 per mole of NO_x will accomplish 50% NO_x removal or above, but the rate should be lowered to 1.5 or below when possible to minimize NH_3 emissions (see Figures 14 and 15).

The NH_3 injection grid is insulated and covers the entire cross-sectional area of the flue gas flow path. Each grid is constructed of separate injection zones with each zone having its own NH_3 controls to deal with temperature fluctuations in a plane normal to the flue gas flow. If multiple grids are used, air is passed through idle grids to prevent plugging

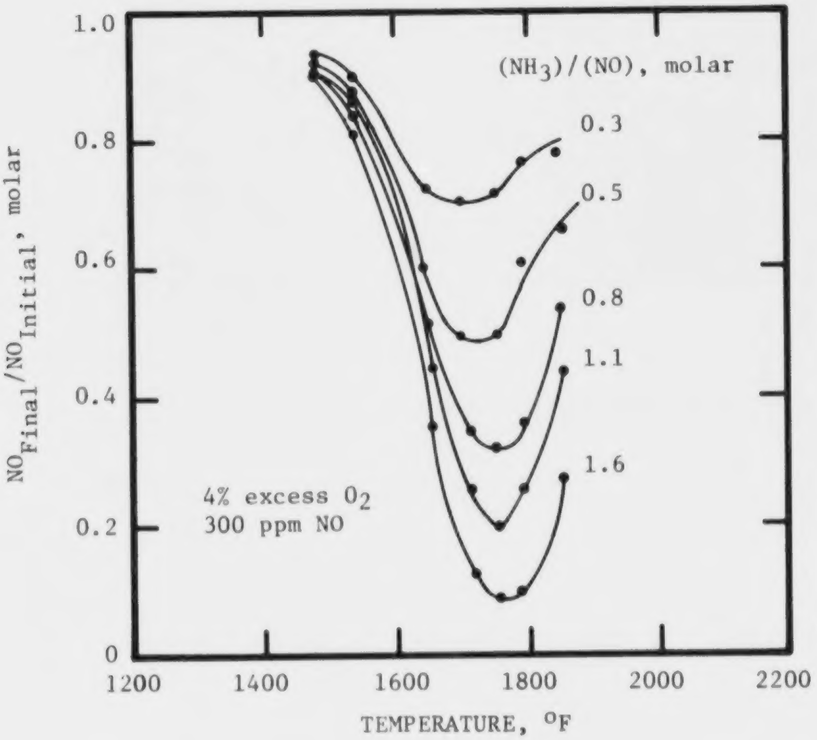

Figure 12. Effect of temperature on NO reduction for various levels of NH_3 injection with the Exxon process (19).

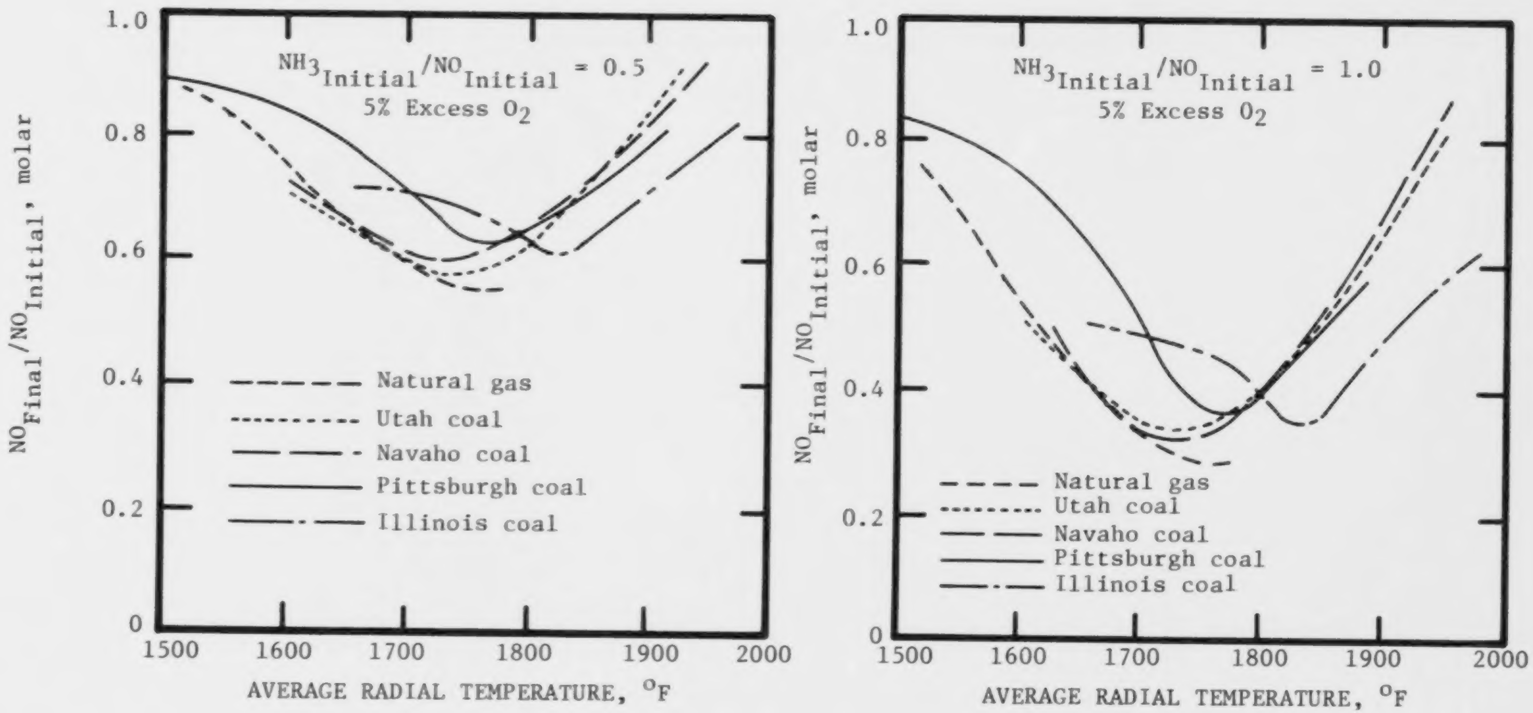

Figure 13. Effect of temperature on NO reduction for various fuel sources with the Exxon process (19).

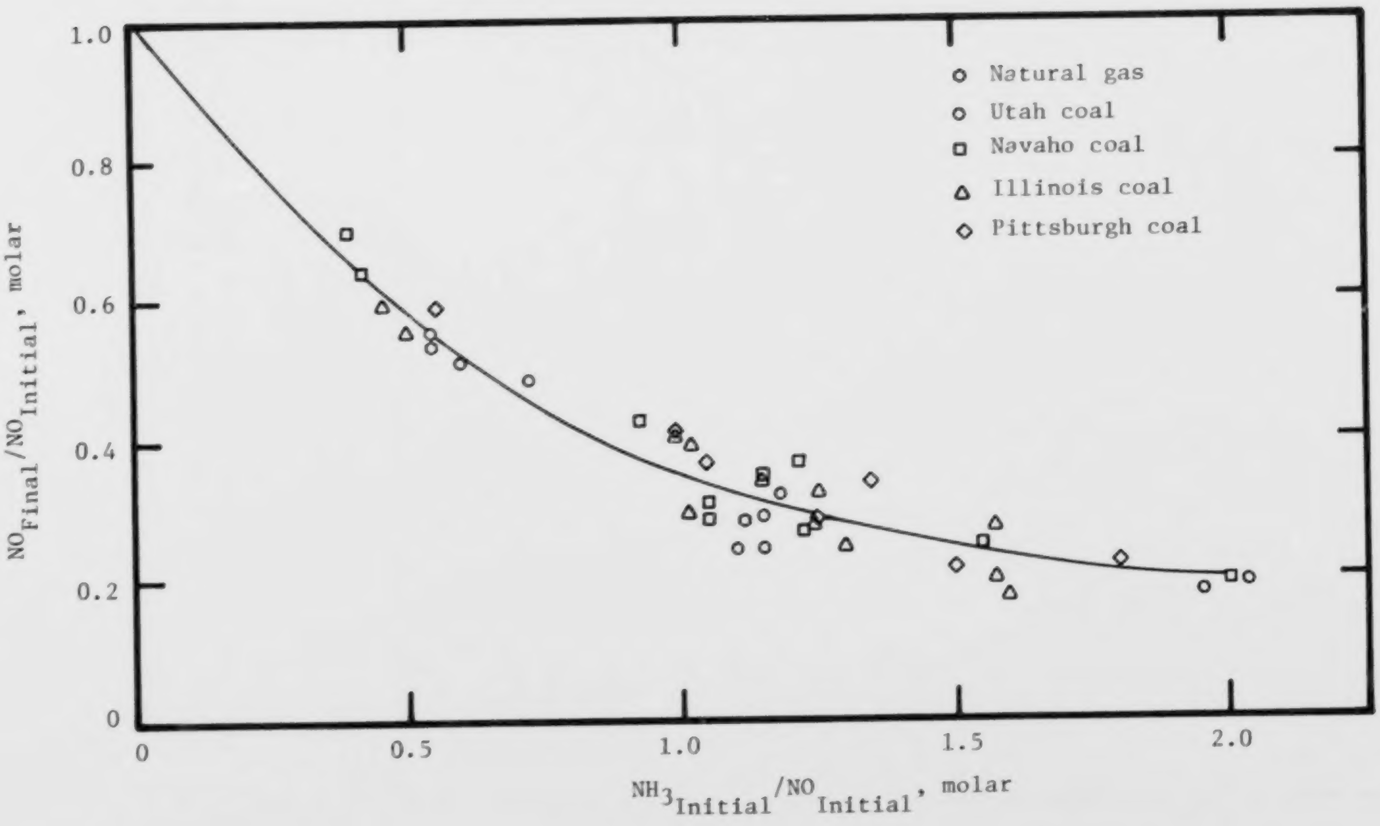

Figure 14. Comparison of NO reductions at the optimum temperature condition with the Exxon process (19).

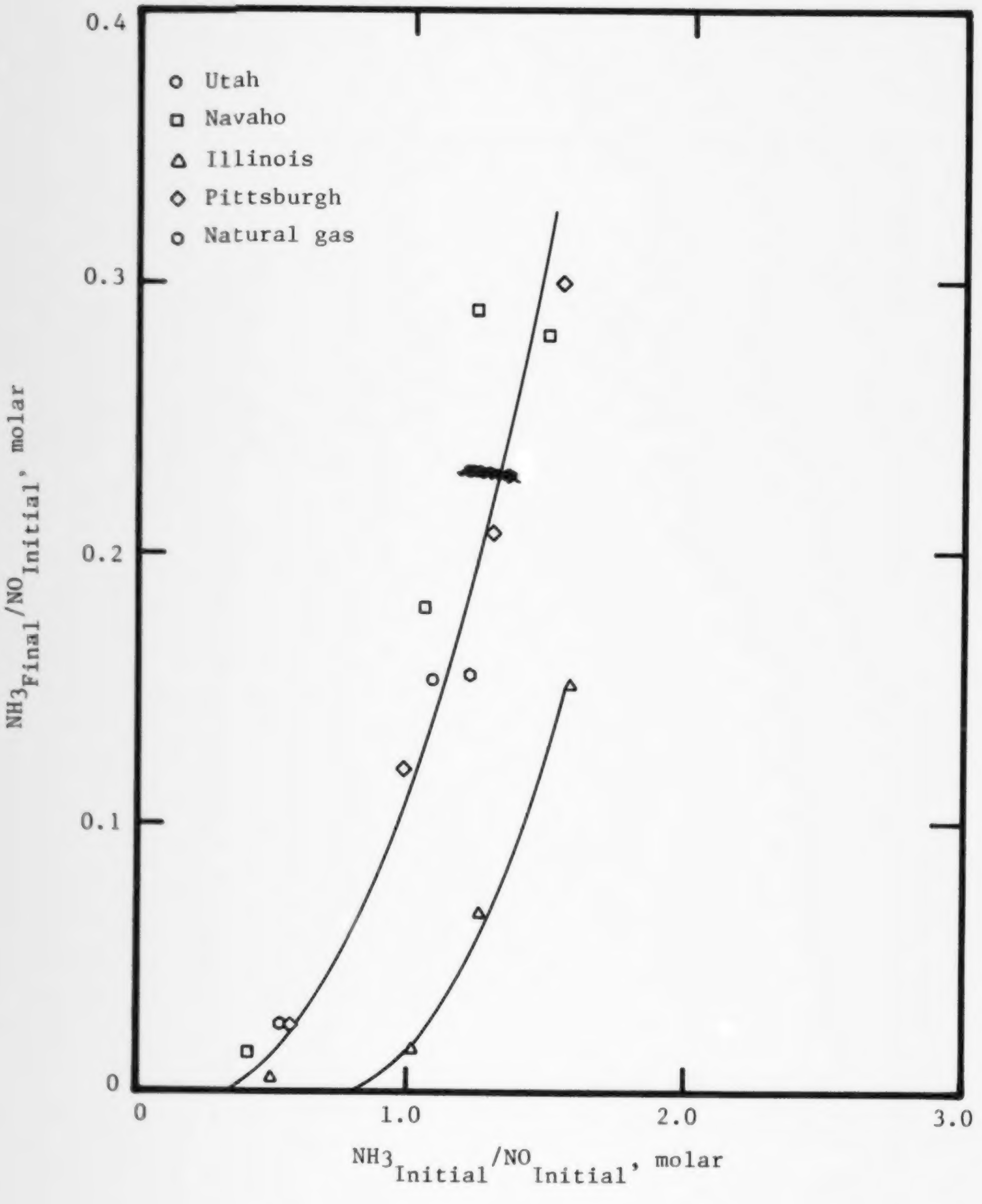

Figure 15. Comparison of the NH_3 emissions for all fuels tested at the peak NO reduction temperature with the Exxon process (19).

of grid holes (no nozzles are used) and to protect the grid from high flue gas temperatures. To prevent loss of carrier air, multiple air compressors are used; however, emergency steam can be connected for use if total air loss occurs.

Since the main process control parameter for the Exxon process is boiler load, initial NH_3 injection rates are established based on calculated or measured flue gas temperatures for a given boiler load or load range including temperature variations across the plane of the injection grid. This is then incorporated into the control system using a microprocessor for responding to load changes. Temperature changes which are not a function of boiler load are also incorporated into the control system allowing injection rates to be optimized, NO_x reduction maximized, and NH_3 breakthrough minimized. Carrier air rate is held constant; therefore, it is not a control variable. To check analyzer response to injection rate, optimization control response logic is built into the microprocessor. Operator intervention is required if large magnitude changes for the system are indicated without significant change in boiler operating parameters.

Technical Considerations

Since flue gas temperature is the most important operating parameter of the Exxon process, anything that causes the temperature to fluctuate can affect the performance of the process. Slagging, changes in boiler load, changes in excess O_2, and other operational variations can cause the temperature profile to shift in relation to the firebox. Variations in flue gas temperature are also present normal to the flue gas flow. Boiler tubes at the walls absorb heat to produce steam; therefore, temperatures at the wall are lower than at the center. In large utility boilers the temperature variation can exceed 270°F.

Two techniques are used by Exxon to deal effectively with the temperature variations. One method uses multiple NH_3 injection grids with each grid positioned in the boiler to correspond to a different load or combination of loads. In this way, as the temperature profile of the boiler shifts due to a load change, the required reaction temperature range, 1,650°F (900°C) to 1,830°F (1,000°C), is accessible by feeding the appropriate grid. The second method uses one grid, instead of using multiple grids, and the reaction temperature is manipulated. This is accomplished by injecting H_2 along with the NH_3. Based on the $H_2:NH_3$ injection ratio selected, NO_x reduction will proceed at a satisfactory rate at a temperature range of 1,290°F (700°C) to 1,830°F (1,000°C). Therefore, one grid can be used to handle load changes because the reaction temperature can be adjusted to the boiler conditions by controlling the H_2 flow rate.

Exxon has developed a performance prediction procedure to optimize grid location in the boiler and to estimate NO_x removal. Variables used in the calculations are: flue gas temperature and flow distribution, including severity of cross-sectional variations, flow path geometry, available reaction time, and suitability of the dimensions of the zone for grid placement, based on manufacturer's data. The procedure will give an estimated NO_x removal percentage at a particular location in the flue gas path.

To optimize grid placement, the performance prediction procedure is used at a number of locations within the boiler to generate a graph of location versus NO_x removal. This is done for 50%, 75%, and 100% boiler load conditions. A combination-load grid, which will serve two of the boiler loads, is situated at the maximum of the intersection points of the load curves. The single-load grid is situated at the maximum of the remaining load curve.

For an actual installation, measurements of the temperature and flow patterns within the predicted zone would be used to confirm or adjust the final grid location. The most frequently used load is emphasized in designing grid placement, so that NO_x emissions can be minimized at that load.

Potential problems with the Exxon process generally relate to NH_3 emissions. Emission levels from a pilot-scale coal-burning test system averaged 11 to 34 ppm NH_3 at the boiler exit. The assessment of the Exxon process using the performance prediction procedure for eight major utility boiler types gave predicted NH_3 levels at the boiler outlet of 21 to 43 ppm for an NH_3:NO mole injection rate of 1.0, and 64 to 129 ppm for an NH_3:NO mole injection rate of 1.5, although these might vary under actual operating conditions. Operating experience on full-scale oil- and gas-fired units shows NH_3 levels of 10 to 40 ppm.

NH_3 emissions when combined with SO_3 can cause problems with $(NH_4)_2SO_4$ and NH_4HSO_4 formation. This is particularly true in coal-fired applications, where sulfur content is relatively high. Studies indicate substantial amounts of $(NH_4)_2SO_4$ and NH_4HSO_4 are deposited in the air heater. Although most of the deposits may be removed by soot blowing, modifications in the air heater design may be required. Operating experience in Japan with low-sulfur oil-fired boilers has shown that water washing of the air heaters is necessary two or three times a year.

The presence of NH_3 in the flue gas has mixed effects on ESP performance. It has been used as a flue gas additive to neutralize condensed H_2SO_4 and reduce reentrainment losses by increasing fly ash cohesiveness (5). However, NH_3 can also cause excessive sparking between the electrodes, especially with low-sulfur, high-resistivity, western coal fly ash. Reactions of NH_3 with SO_3 will deplete the SO_3 content of the flue gas which lowers collection efficiency. The net effect of these factors on ESP performance is unclear. It is also unclear at this time whether the NH_3, $(NH_4)_2SO_4$, or NH_4HSO_4 will present additional operating requirements for SO_2 scrubber systems, such as waste water treatment.

Development Status

The reaction mechanism of the Exxon process was developed by Exxon using simulated flue gases in a bench-scale reactor. When the reaction mechanism was established, evaluation of operating parameters such as reaction temperature and NH_3 injection rate was performed on a 0.3-MW_t (10^6 MBtu/hr) oil- and gas-fired boiler. Corrosion and fouling effects were tested on a 9-MW_t (30 MBtu/hr) oil- and gas-fired boiler.

Commercial application of the Exxon process is primarily limited to gas- and oil-fired units in Japan, as shown in Table 2. The Los Angeles Department of Water and Power's Haynes Electrical Generating Station is scheduled to be the first U.S. electric utility to install the Exxon process (20) with startup projected for May 1981. The Haynes Unit 4 is a 230-MW boiler burning either No. 6 fuel oil containing 0.25% sulfur or gas. Predicted performance for the Exxon process is 51% NO_x reduction at full load using one NH_3 injection grid containing six zones. Exxon is guaranteeing the process for 90% of the predicted performance which is 46% NO_x reduction. At 50% boiler load, no NO_x reduction is guaranteed.

Although no commercial application of the Exxon process on a coal-fired boiler has yet been made, studies have been made to assess the possibility of such an application. A coal-fired pilot-plant study, sponsored by Exxon Research and Engineering and EPRI and run by KVB, Incorporated, was completed in early 1978. The project utilized a fire tube boiler, 0.9 MW_t (3 MBtu/hr), modified to fire pulverized coal with preheated air. Three bituminous and one subbituminous coals were fired. A 65% NO_x reduction could be obtained for all coals with a 1:1 NH_3:NO_x molar ratio feed rate. Optimum operation, that is, maximum NO_x reduction and minimum NH_3 emissions, was 55% NO_x reduction and 10 to 35 ppm NH_3 emitted. Hydrogen injection was tested with one coal and found to increase NO_x reduction and decrease NH_3 emissions.

Under contract with EPA, eight different pulverized-coal-fired boiler designs were assessed by Exxon to predict the applicability of the Exxon process. This was done using the Exxon-developed performance prediction procedure and boiler design data supplied by the manufacturer. Each boiler design was evaluated at 100%, 75%, and 50% load. As a basis two injection grids were used and there was no H_2 addition. The best predicted results of any design, coal type, and load at an NH_3:NO_x molar ratio of 1.5:1 was 63% NO_x reduction and the worst was 45% NO_x reduction (28). Using updated technology, Exxon now states that the predicted NO_x reductions would be 10-20 percentage points higher.

HITACHI ZOSEN PROCESS

Process Description

Hitachi Zosen has developed a process for the dry SCR of NO_x with NH_3 (32). U.S. licensee for the Hitachi Zosen process is the Chemico Air Pollution Control Corporation. The process is based on a catalyst and a reactor design developed by Hitachi Zosen that permits treatment of the flue gas with a high particulate loading. Therefore, flue gas from a coal-fired boiler may be fed directly to the reactor, upstream of the air heater, without previous particulate removal. The reactor pressure drop is 2 to 3 inches H_2O. An NH_3-air, NH_3-steam, or NH_3 - flue-gas mixture is injected into the flue gas upstream of the reactor at an NH_3:NO_x molar ratio of 1:1 to achieve 90% NO_x removal. Automatic control of the NH_3 flow rate is

TABLE 2. SUMMARY OF COMMERCIAL APPLICATIONS OF

EXXON THERMAL DENO$_x$ PROCESS

Source	Location	Fuel	Heat release, MBtu/hr	Approximate initial NO$_x$ emissions, vppm	Reduction efficiency, %
Industrial boiler	Japan	Oil/gas	215	185	55
Cogeneration boiler	Japan	Oil/gas	1,135	140	60
Cogeneration boiler	Japan	Oil/gas	1,135	140	60
CO boiler	Japan	CO gas/gas	400	160	50
Petroleum heater	Japan	Gas	515	130	63
Petroleum heater	Japan	Gas	190	130	63
Industrial boiler	Japan	Oil	340	135	53
Petroleum heater	Japan	Oil/gas	250	79	51
Petroleum heater	Japan	Oil/gas	250	85	53
Oilfield steamer	California	Crude oil	50	270	65
Utility boiler	Japan	Oil	1,210	160	45
Utility boiler	Japan	Oil	3,000	150	33
Utility boiler	Japan	Oil	1,500	100	35
Refuse incinerator	Japan	Refuse/gas	–	100–180	20–70
Utility boiler	Japan	Oil	2,900	110–140	40
*Refinery heaters (14), boiler (1)	California	Oil/gas	647 (total)	100–125	50–60
**Refinery heaters (4), boilers (2)	California	Oil/gas	349 (total)	100–150	50
**Utility boiler	California	Oil/gas	2,100	200	51
Glass melting furnace	California	Gas	150	1,500–2,000	>50
**Petroleum heater	California	Gas	150	75	50
**Petroleum heaters (2)	California	Gas	47 (total)	82	>60
**Refuse incinerator	California	Refuse/gas	160	216	>60

*Two heaters in operation, remainder not yet in operation.
**Not yet in operation.

based on the flue gas flow rates and the inlet NO_x concentration and it is optimized using the outlet NO_x and NH_3 concentrations. NH_3 is diluted by air to 5% or by steam or flue gas to 5% to 20%. This enhances mixing and places the NH_3-air mixture outside of the flammability limits of 15.5% to 27.0%.

In the reactor, NO_x is reduced to N_2 by a reaction with NH_3 in the presence of a catalyst at an optimum temperature of 734°F. The reactions are listed by Hitachi Zosen as follows:

$$4NO + 4NH_3 + O_2 \rightarrow 4N_2 + 6H_2O \quad (1)$$

$$6NO + 4NH_3 \rightarrow 5N_2 + 6H_2O \quad (2)$$

$$2NO_2 + 4NH_3 + O_2 \rightarrow 3N_2 + 6H_2O \quad (3)$$

$$6NO_2 + 8NH_3 \rightarrow 7N_2 + 12H_2O \quad (4)$$

$$4NH_3 + 3O_2 \rightarrow 2N_2 + 6H_2O \quad (5)$$

Reactions (1) and (3) predominate when the molar ratio of $NH_3:NO_x$ is approximately 1:1, which is required for 90% NO_x reduction; however, reactions (2) and (4) gain dominance as the $NH_3:NO_x$ molar ratio becomes less than equimolar. Reaction (5) represents the breakdown of NH_3 by O_2. This undesirable reaction becomes a problem at higher than optimum temperatures. At the optimum reactor temperature or below, it is insignificant. Hitachi Zosen reports that the level of excess NH_3 in the flue gas leaving the system is low (<10 ppm). After leaving the reactor, the treated flue gas flows to the air heater.

Technical Considerations

The temperature range required to achieve 90% NO_x reduction is 600°F to 750°F. As can be seen in Figure 16, additional reduction can be obtained at temperatures higher than the acceptable range but NH_3 decomposition becomes more prevalent. Below the acceptable temperature range reduction efficiency becomes unsatisfactory. Since flue gas temperature will fluctuate with the boiler load, some method must be employed at low load to raise the flue gas temperature to acceptable reactor conditions. Four techniques that can be used are to operate an auxiliary furnace, to bypass hot flue gas around the economizer, to reduce water flow to the economizer, or use a split economizer design. It might also be possible to design for low-load conditions adequate to maintain the required NO_x reduction efficiencies. It may be possible that low loads will not have an adverse effect on NO_x reduction efficiency since reduced loads will decrease the amount of flue gas to be treated, resulting in an increased residence time in the reactor. Therefore, the decreased temperatures may be offset by the increased residence time.

To reduce the effects of high fly ash loadings from coal-fired flue gas on the catalyst, Hitachi Zosen uses a corrugated configuration (see Figure 17) and the flue gas passes parallel to the catalyst surface. Because of this

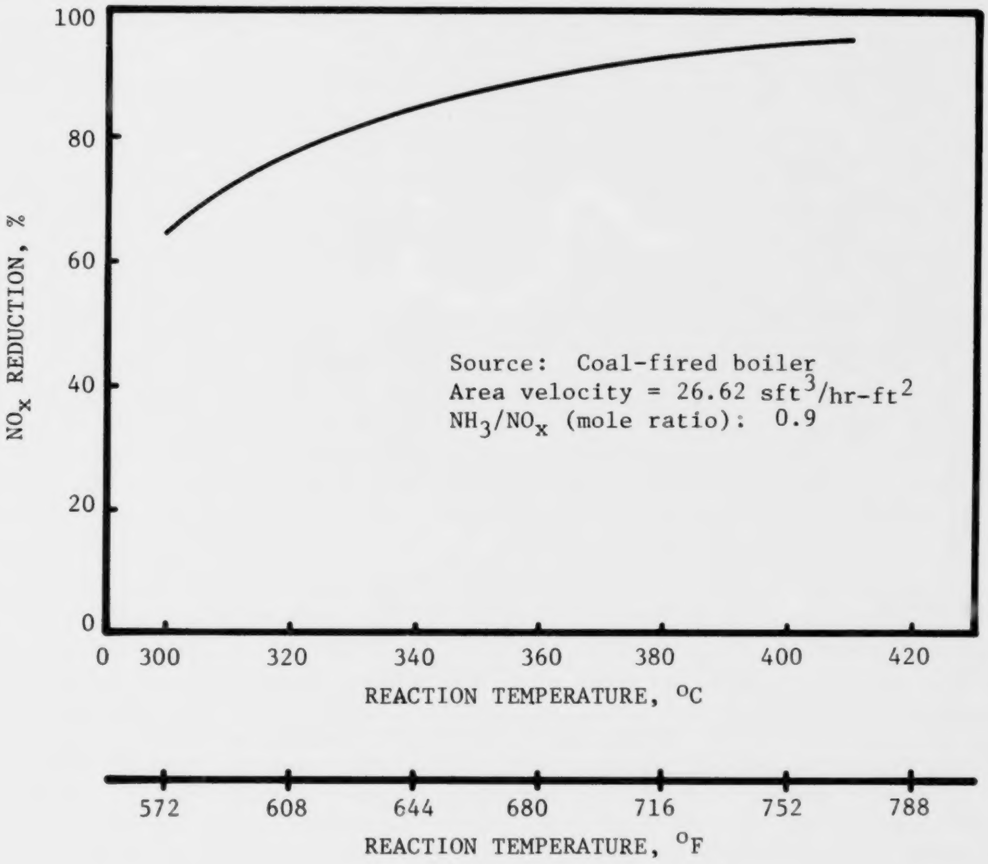

Figure 16. NO_x reduction versus reaction temperature for the Hitachi Zosen process (32).

unique configuration, area velocity (volumetric flue gas flow rate/catalyst geometric surface area) rather than space velocity (volumetric flue gas flow rate/reactor volume) is used to determine the quantity of catalyst required. Hitachi Zosen reports that the area velocity recommended for 90% NO_x reduction is between 22.8 and 33 $ft^3/hr-ft^2$, which corresponds to a space velocity of 5,000 to 10,000 $ft^3/hr-ft^3$. The stoichiometric requirement is given primary consideration when determining the $NH_3:NO_x$ molar ratio required to achieve a given NO_x reduction, but other factors must also be considered. The stoichiometric requirement determines the amount of NH_3 that must be injected if NH_3 usage is 100% efficient. However, inefficiencies result from incomplete mixing of NO_x and NH_3 and consumption of NH_3 by reactants other than NO_x. Because of these inefficiencies in NH_3 usage, excess NH_3 must be injected. Here, care must be taken since too much additional NH_3 will result in increased levels of unreacted NH_3 passing through the reactor. If this occurs, the breakthrough NH_3 becomes a pollutant. Figure 18 shows representative curves of NO_x removal efficiency and exhaust NH_3 as a function of the $NH_3:NO_x$ molar ratio.

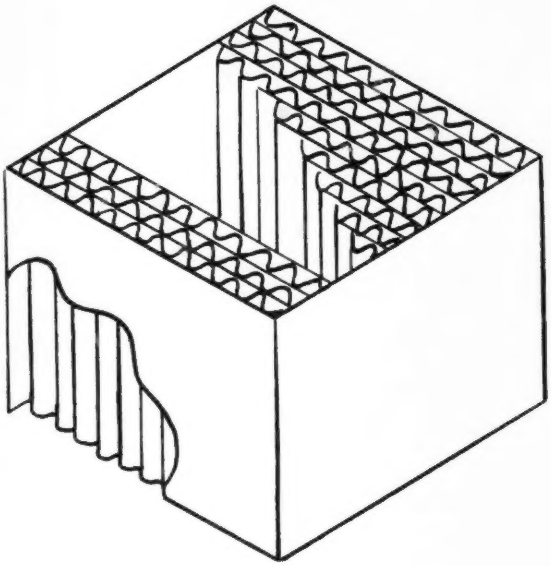

Figure 17. Configuration of Hitachi Zosen NOXNON 500 and 600 series catalyst (32).

The oxidation of SO_2 can be a problem in NO_x catalytic reduction. The catalyst composition may cause <1% of the SO_2 in the flue gas to be oxidized to SO_3, which will combine with NH_3 to form $(NH_4)_2SO_4$ and NH_4HSO_3. These deposit as sticky solids on equipment

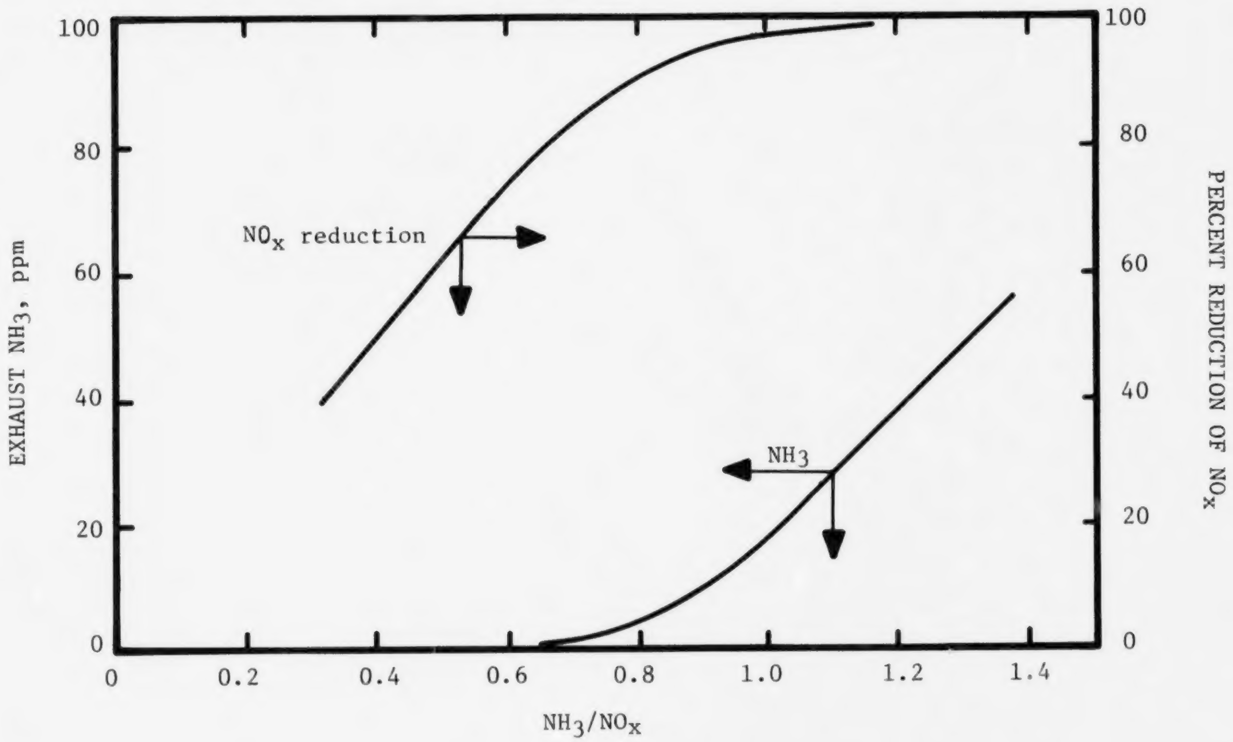

Figure 18. Relationship between exhaust NH_3, NO_x reduction, and molar ratio for the Hitachi Zosen process (32).

at low temperatures. The sulfate and bisulfate formation temperatures are dependent on the NH_3 and SO_3 concentrations as can be seen in Figure 19. Air heater plugging, catalyst masking, and equipment corrosion are the primary problems related to the deposits. However, Hitachi Zosen states that the deposits can be removed by soot blowing or water washing.

Pressure drop for the reactor and catalyst is reported to be 2 to 3 inches H_2O by Hitachi Zosen and should not increase significantly over the catalyst life. Figure 20 shows a typical pressure drop versus operating time profile for a Hitachi Zosen catalyst.

Catalyst life is dependent on a number of factors including the resistance of the surface to abrasion by particulate matter, the masking of the catalyst by fine particulates, and chemical attack by compounds in the flue gas. Figure 21 is a plot of the percent NO_x reduction versus catalyst age. As can be seen NO_x reduction decreases with age. The loss in NO_x reduction efficiency can be a result of abrasion gradually removing possible reaction sites. Additional reaction sites can be lost as a result of fine fly ash particles plugging pores in the catalyst surface. Fly ash plugging can be reduced by regular soot blowing. SO_3 and other trace elements in flue gas can chemically attack the catalyst causing loss in reactivity. Hitachi Zosen claims their catalyst is resistant to attack of this nature, however.

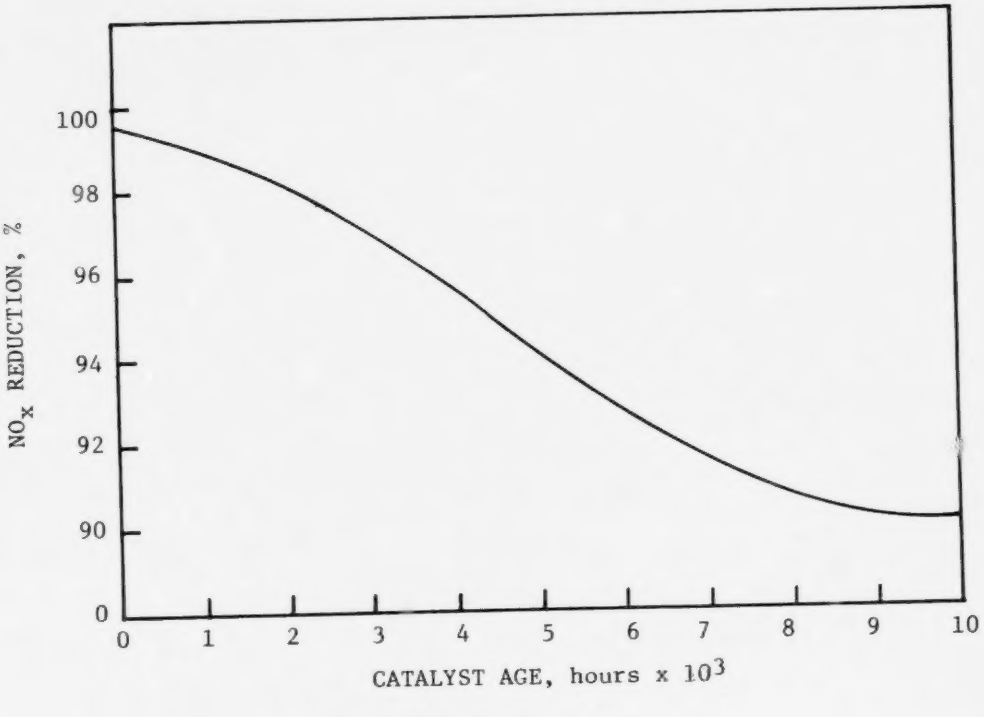

Figure 21. NO_x reduction versus catalyst age for the Hitachi Zosen process (32).

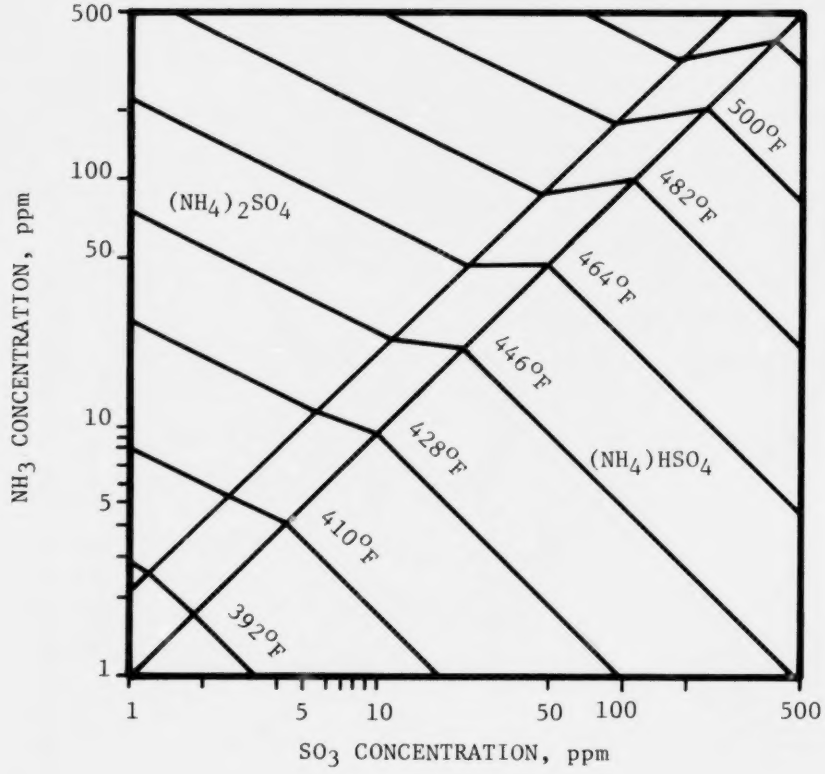

Figure 19. Conditions for the formation of ammonium sulfate/bisulfate (32).

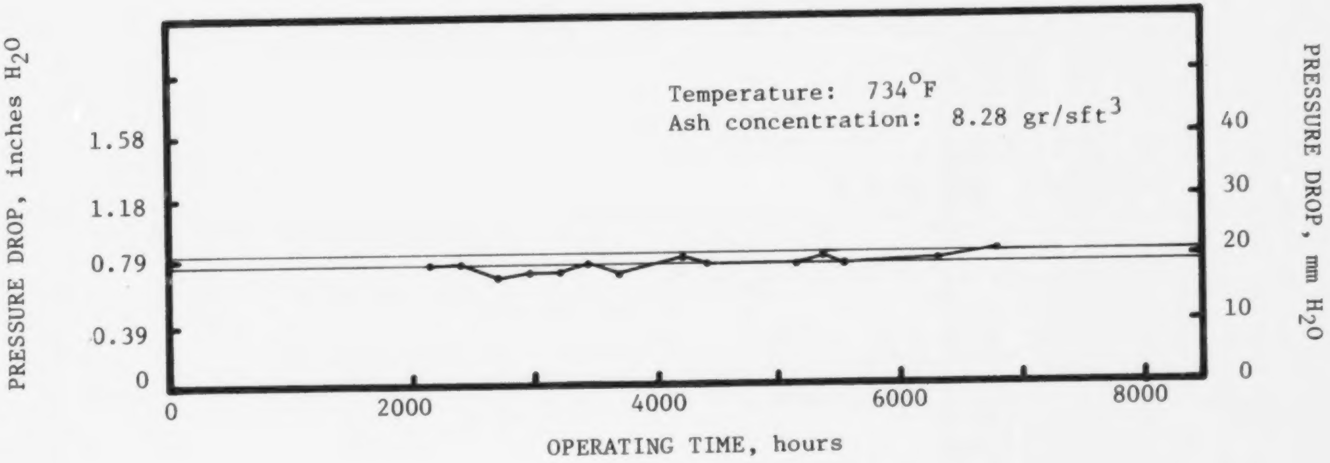

Figure 20. Pressure drop versus operating time for the Hitachi Zosen process (32).

The reactor inlet NO_x concentration has no effect on NO_x reduction efficiency in the range of 150 to 650 ppm of inlet NO_x, as shown in Figure 22, provided that the required NH_3:NO_x molar ratio is maintained. As shown in Table 3 it can be seen that NO_x reduction efficiency is independent of inlet SO_2 and H_2O concentrations. The presence of 1% to 2% O_2 in the flue gas is necessary for NO_x control, as shown in Figure 23.

TABLE 3. INFLUENCE OF SO_2 AND H_2O

CONCENTRATIONS

Inlet concentration		Temperature/NO_x reduction, %			
SO_2, ppm	H_2O, %	392°F	482°F	572°F	662°F
0	10	55	73	86	94
250	10	54	73	85	93
250	0	59	73	87	93

Basis: Temperature: 392°F to 662°F
Area velocity: 34.7 $sft^3/hr\text{-}ft^2$
NH_3:NO_x (mole ratio): 1.0

Development Status

Hitachi Zosen has been developing an NO_x control process and catalyst since 1970. Six different catalyst series have been developed. They are known as NOXNON 100, 200, 300, 400, 500, and 600. The 100 series is nonselective, for use with CO, H_2, and hydrocarbons as reducing agents. NH_3 is the reducing agent for the five remaining series. Series 200 is used for treating clean flue gas, that is, gas which does not contain a significant amount of SO_x or particulate matter. The 300 and 400 series are resistant to SO_x. The NOXNON 500 and 600 catalyst were developed to have the following characteristics:

- High selectivity for adsorption and reaction activation of NH_3 and NO_x
- Immunity to SO_x attack, especially by SO_3
- A low pressure drop
- Tolerance to plugging from gases with high particulate loadings

A corrugated, honeycomb-type configuration was found to be the most suitable for these conditions. The NOXNON 500 Type II catalyst was tested for

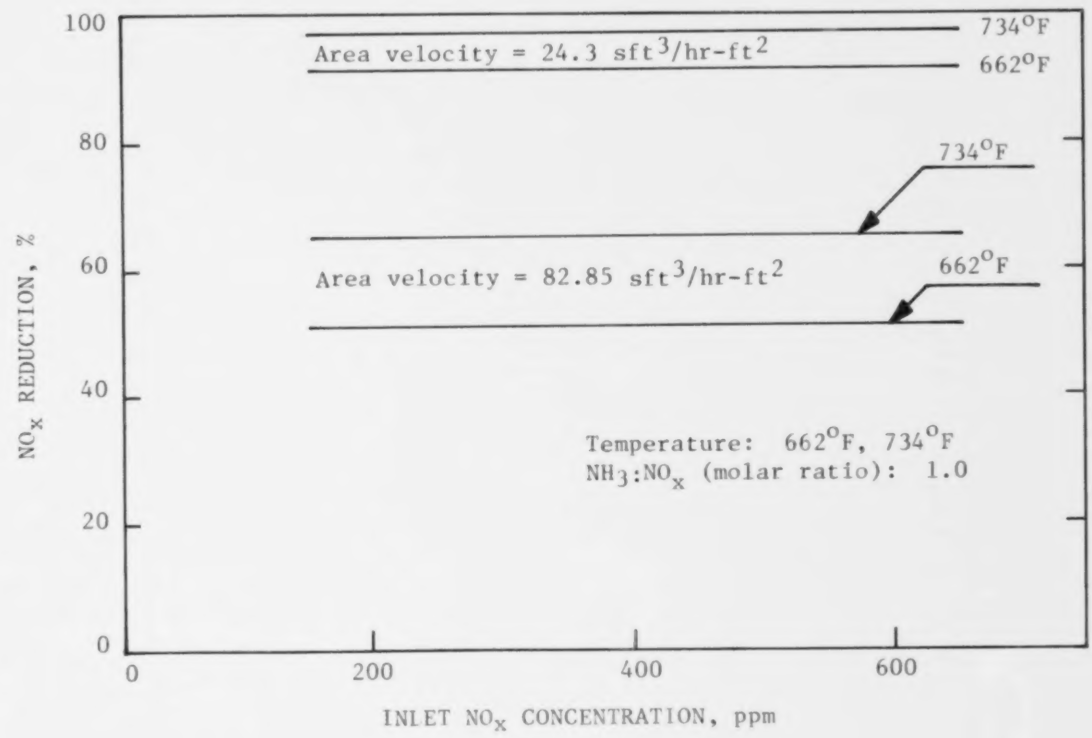

Figure 22. Influence of NO_x concentration on NO_x reduction with the Hitachi Zosen process (32).

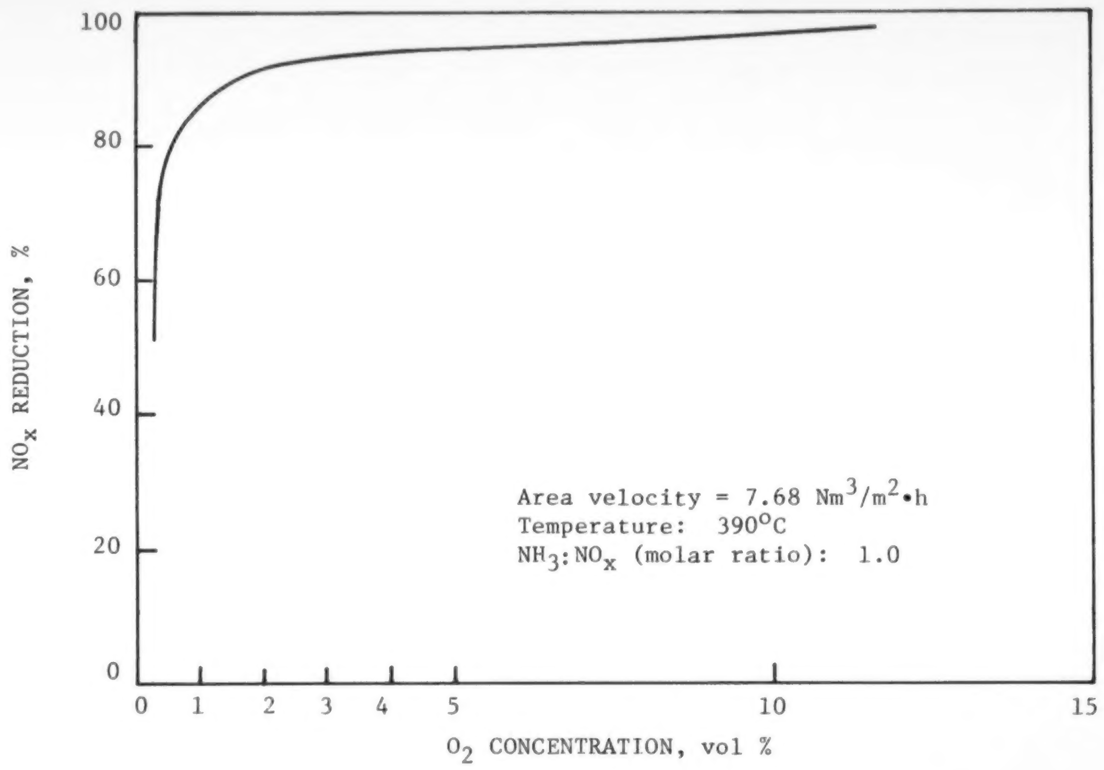

Figure 23. Influence of O_2 concentration on NO_x reduction for the Hitachi Zosen process (32).

over 8,000 hours with a negligible increase in pressure drop, although catalyst activity exhibited a sharp initial decrease due to abrasion of protruding active sites on the surface. The NOXNON 500 Type III catalyst was designed specifically for increased surface hardness, which was demonstrated in over 3,500 hours of testing for abrasion resistance. The NOXNON 600 catalyst has the same composition as the 500 series catalyst but the solid metal support used in the 500 series was replaced by a wire mesh support. The NOXNON 600 catalyst was tested for over 14,000 hours with a negligible increase in pressure drop and stable NO_x removal efficiency.

Since the beginning of catalyst development, a total of 41 pilot plants have been constructed by Hitachi Zosen (see Table 4). While a majority of these pilot plants are at oil- and gas-fired installations, there are three pilot plants at coal-fired installations. The most significant work in coal-burning applications was performed at the Isogo Station of the Electric Power Development Company of Japan. In 1978, EPA contracted with Hitachi Zosen to build a 0.5-MW-size pilot plant at the coal-burning Mitchell Station of the Georgia Power Company.

TABLE 4. HITACHI ZOSEN PILOT-PLANT EXPERIENCE

	No. of plants
Heavy fuel-oil-fired boilers	21
LNG- and LPG-fired furnaces	6
Iron ore sintering	3
Heavy oil-fired cement kilns	2
Heavy oil-fired glass smelting furnaces	2
Coke ovens	3
Coal-fired power plants	3
LPG-fired simulation gas (for gas turbine)	1
Total	41
Total raw gas flow through test plants	35,130 Nm^3/hr

There are no existing commercial applications of the Hitachi Zosen process on coal-fired boilers. Table 5 lists nine commercial installations using other fuels.

TABLE 5. COMMERCIAL PLANTS USING THE HITACHI ZOSEN PROCESS

	Customer	Treating capacity, Nm^3/hr	Flue gas source	Process	Completion
1	Osaka Gas Company, Sakai	53,000	LNG- or naphtha-fired furnace	Ammonia reduction	1975
2	Daiki Engineering, Chiba	5,000	LPG-fired furnace	Ammonia reduction	1975
3	Idemitsu Kosan, Chiba	350,000	Co boiler and gas-fired heater	Ammonia reduction	1975
4	Shin-Daikyowa Petrochemical, Yokkaichi	440,000	Fuel-oil-fired boiler with wet-type desulfurization	Ammonia reduction	1975
5	Hitachi Zosen, Osaka	6,000	Gas-fired annealing furnace	Ammonia reduction	1975
6	Toshin Steel Mill, Himeji	70,900	Kerosene-fired steel heating furnace	Ammonia reduction	1976
7	Kawasaki Steel, Chiba	762,000	Iron ore sintering plant with wet-type desulfurization	Ammonia reduction	1976
8	Nippon Satetsu, Himeji	10,000	Fuel-oil-fired steel heating furnace	Ammonia reduction	1977
9	Maruzen Petrochemical Company (formerly Kansai Oil Company), Sakai	150,000	Fuel-oil-fired boiler	Ammonia reduction	1979

PREMISES

The following premises were used for the comparative economic evaluations of the processes in this study. The premises are for projects with a construction schedule starting in 1981 and ending in 1983, with 1984 as the first year of operation.

DESIGN PREMISES

Plant Size and Fuel

The power unit is a new, coal-fired, horizontally opposed, balance-draft boiler burning pulverized coal. A 30-year life and a north-central location (Illinois, Indiana, Ohio, Michigan, and Wisconsin) has been assumed. The unit has a net output of 500 MW including all system energy requirements up to and including the ESP's and the induced draft (ID) fans. This does not include the energy usage of any flue gas treatment processes. The unit has a design heat rate of 9,500 Btu/kWh. Utility basic mechanical equipment is shown in Table 6.

TABLE 6. COAL PLANT BASE MECHANICAL EQUIPMENT

Total plant electrical capacity[a]	2,000 MW
Unit rated electrical capacity[a]	500 MW
Steam generator type	Balanced draft Horizontally fired, dry bottom Pulverized coal
Design heat rate	9,500 Btu/kWh
Fly ash removal type	Cold-side electrostatic precipitator
Fly ash removal efficiency	99.8%

a. Net including system energy usage up to and including ESP's and the ID fans (does not include FGD or FGT).

Fuel for the plant is a coal having a heating value of 11,700 Btu/lb as fired and containing 3.5% sulfur and 15.1% ash. The coal composition and the input coal requirements (based on a heat rate of 9,500 Btu/kWh) for the 500-MW boiler are listed in Table 7. The capacity factor is equivalent to 5,500 hours of operation at full load.

TABLE 7. BASE CASE COAL
COMPOSITION
AND INPUT FLOW RATE

(500-MW new unit,
9,500 Btu/kWh heat rate)

Component	Wt %, as fired	Lb/hr
C	66.7	270,800
H_2	3.8	15,400
N_2	1.3	5,300
O_2	5.6	22,700
S	3.4	13,800
Cl	0.1	400
Ash	15.1	61,300
H_2O	4.0	16,300

Flue Gas Composition

Flue gas compositions are based (2) on combustion of pulverized coal assuming a total air rate after the air preheater equivalent to 139% of the stoichiometric requirement. This includes 20% excess air to the boiler and 19% additional air inleakage at the air preheater.

It is assumed that 80% of the ash present in the coal is emitted as fly ash and that 92% of the sulfur is emitted as SO_x. Three percent of the sulfur emitted as SO_x is SO_3 and 100% of the chlorine is emitted as HCl. NO_x emissions are assumed to be 0.6 lb equivalent NO_2/MBtu with 95% being NO and 5% NO_2. Table 8 gives the composition and flow rate at the economizer outlet for untreated flue gas.

NO_x Control System

Proper reheating credits or debits are assigned as applicable for NO_x removal. For dry catalytic processes, catalyst replacement occurs during boiler outages and does not affect boiler on-stream time. Spent catalyst disposal costs are assumed to be zero, with the catalyst support salvage value being equal to the catalyst coating removal and disposal costs. This assumption may be unique to the Hitachi Zosen catalyst which employs a metallic support made of stainless steel. It may not apply to ceramic supports or homogeneous catalyst. Even with salvage of the metallic support, disposal costs may be greater than zero; however, Hitachi Zosen feels that this is a reasonable assumption for their catalyst. A sufficient quantity of catalyst to ensure the desired removal efficiency is maintained. Redundancy and the number of modules for dry processes are based on the NO_x removal system module availability and the required NO_x removal efficiency. For this study, the NO_x removal system availability is assumed to be 100% so that no redundant trains are needed. Redundancy is achieved through sparing vital equipment in the NH_3 vaporization and injection system.

TABLE 8. FLUE GAS COMPOSITION

AND FLOW RATE AT THE ECONOMIZER OUTLET

(500-MW new unit, coal fired, 9,500 Btu/kWh, 3.5% S, 11,700 Btu/lb HHV as fired, 2,249,000 aft^3/min at 705°F)

Component	Vol, %	Lb/hr
N_2	74.86	3,326,900
O_2	3.27	165,800
CO_2	14.21	992,300
SO_2	0.24	24,600
SO_3	0.008	953
NO	0.037	1,765
NO_2	0.002	143
HCl	0.007	416
H_2O	7.36	210,200
Ash	-	49,000
	100.00	4,772,100 (approx.)

Since it is presently unclear whether the presence of nitrogen compounds in waste water as a result of air heater washing to remove NH_3 compounds is a significant problem for U.S. applications, no provisions are made for the treatment of waste water.

Separate ID fans are not included for the systems. Rather, a larger boiler ID fan is used to compensate for the higher pressure drop of the combined boiler-FGT system and the increased costs are assigned to the FGT process.

Raw Materials

All raw materials used are assumed to be received by either rail or truck. Thirty-day storage facilities at full load are provided.

ECONOMIC PREMISES

The capital structure is assumed to be 35% common stock, 15% preferred stock, and 50% long-term debt. The cost of capital is 11.4% for common stock, 10.0% for preferred stock, and 9.0% for long-term debt. The weighted cost of capital is 10.0% and the discount rate is 10% (8).

A 30-year economic life and a 30-year tax life are assumed for the utility plant. Salvage value is less than 10% and is equal to removal costs. The annual sinking fund factor for a 30-year economic life and 10.0% weighted cost of capital is 0.61%. The use of the sinking fund factor does not indicate that regulated utilities commonly use sinking fund depreciation. The sinking fund factor is used because it is equivalent to straight-line depreciation levelized for the economic life of the facility using the weighted cost of capital. The depreciation schedule for other types of plants or facilities is based on their expected useful life.

An annual interim replacement allowance of 0.56% is also included as an adjustment to the depreciation account to ensure that the initial investment will be recovered within the actual rather than the forecast life of the facility (12). Since power plant retirements occur at different ages, an average service life is estimated. The interim replacement allowance does not cover replacement of individual items of equipment since these are covered by the maintenance charge.

The sum of the years digits method of accelerated depreciation is used for tax purposes. For a 50% tax rate, 30-year tax life, 30-year book life, 10.0% weighted cost of capital, and a 0.61% sinking fund factor, the annual levelized accelerated depreciation credit is 1.36%. Using a 10% investment tax credit rate the levelized investment tax credit is 1.92% annually. For a 10.61% capital recovery factor (weighted cost of capital plus sinking fund factor), 0.56% allowance for interim replacements, 3.3% straight-line depreciation, 50% debt ratio, 9.0% debt cost, and a 50% income tax rate, the levelized income tax rate is 4.31%.

The levelized annual capital charges as shown in Table 9 are 14.7% of the total investment. The annual capital charge includes charges for the capital recovery factor, interim replacements, insurance and property taxes, State and Federal income taxes, and credits for investment credit and accelerated depreciation.

The annual capital charge is applied to the total capital investment. It is recognized that land and working capital (except spare parts) are not depreciable and that provisions must be made at the end of the economic life of the facility to recover their capital value. In addition, investment credit and accelerated depreciation credit cannot be taken for land and working capital (except spare parts). The cumulative effect of these factors makes an insignificant change in the annual capital charge rate in most cases and is therefore ignored.

TABLE 9. LEVELIZED ANNUAL CAPITAL CHARGES

FOR REGULATED UTILITY FINANCING

	Capital charge, %
Capital recovery factor	10.61
Interim replacements	0.56
Insurance and property taxes	2.50
Levelized income tax	4.31
Investment credit	(1.92)
Accelerated depreciation	(1.36)
Total	14.70

Capital Investment Estimates

Capital investment estimates are based on a north-central location (Illinois, Indiana, Ohio, Michigan, Wisconsin) and represent projects beginning 1981 and ending 1983. Capital cash flows for a standard project are assumed to be 25% the first year, 50% the second year, and 25% the third year of the project life. Capital costs are projected to mid-1982, which represents the midpoint of the construction expenditure schedule.

The preliminary capital cost estimates are considered to have a -20% to +40% range of accuracy for the Hitachi Zosen and Exxon processes. They are based on a process description, flowsheet, material balance, and equipment list. Piping, ductwork, and instrumentation are factored. The range of accuracy for the cost of the ALNB is -20% to +100%. It is based on the best fixed capital investment estimate for incremental costs above present burner costs now available from boiler manufacturers.

The total fixed capital investment consists of direct capital costs, engineering design and supervision, construction expense, contractor fees, and contingency. The total capital investment includes the total fixed capital investment plus allowances for startup and modification, royalties, the cost of funds during construction, plus the cost of land, working capital, and, where applicable, cost of the initial catalyst charge.

Direct Investment--

Direct capital costs cover process equipment, piping, insulation, transport lines, foundations, structural, electrical, instrumentation, raw material and byproduct storage, site preparation and excavation, buildings, roads and railroads, trucks, and earthmoving equipment. Direct investments are prepared using standard estimation techniques (22, 24) and the average annual Chemical Engineering (6) cost indexes and projections as shown in Table 10. A premium for 7% overtime is included in the construction labor. Appropriate amounts for sales tax and for freight are included in the process capital costs.

TABLE 10. COST INDEXES AND PROJECTIONS

Year:	1978	1979[a]	1980[a]	1981[a]	1982[a]	1983[a]	1984[a]
Plant	218.8	240.2	259.4	278.9	299.8	322.3	344.9
Material[b]	240.6	262.5	286.1	309.0	333.7	360.4	385.6
Labor[c]	185.9	209.7	226.5	244.6	264.2	285.3	305.3

a. TVA projections.
b. Same as index in Chemical Engineering (24) for "equipment, machinery, supports."
c. Same as index in Chemical Engineering (24) for "construction labor."

Necessary electrical substations, conduit, steam, process water, fire and service water, instrument air, chilled water, inert gas, and compressed air distribution facilities are included in the utilities investment. These facilities are costed as increments to the facilities already required by the power plant. Services, nonpower plant utilities, and miscellaneous are estimated at 6% of the total process capital.

Indirect Investment--

Indirect capital investment consists of engineering design and supervision, architect and engineering contractor costs, construction costs, contractor fees, and contingency. Construction costs, which consist of costs for mobile equipment, temporary lighting, construction roads, water supply, construction safety and sanitary facilities, and other similar expenses incurred during construction are considered as part of construction expenses and are charged to indirect capital investment.

Listed below are the factors used to determine the indirect capital cost.

	% of direct investment
Engineering design and supervision	7
Architect and engineering contractor	2
Construction expense	16
Contractor fees	5
Total	30

A contingency of 20% has been included for unforeseen expenses. It is based on the sum of the direct investment less waste disposal and the above indirect investments.

Other Capital Investments--

Startup and modification allowances are 10% of the total fixed investment. For proprietary processes, the actual royalty fees are charged. Working capital is the total amount of money invested in raw materials, supplies, accounts receivable, and monies on deposit for payment of operating expenses. Working capital is the equivalent cost of 1 month's raw material cost, 1.5 months' conversion cost, and 1.5 months' plant and administrative overhead costs. In addition, it includes 3% of the total direct investment to cover spare parts, accounts receivable, and monies on deposit to pay taxes and accounts payable. Land cost is assumed to be $5,000 per acre. For the Hitachi Zosen process, a 1982 initial catalyst charge of $600/ft^3 is also included.

Annual Revenue Requirements

Annual revenue requirements use 1984 costs and are based on 5,500 hours of operation per year at full load.

Direct Operating and Maintenance Costs--

Direct costs include raw materials, labor, utilities, maintenance, and analytical costs. Raw material, labor, and utility costs are listed in Table 11.

Unit costs for steam and electricity are based on the assumption that the required energy is purchased from another source. Unit costs ($/kW, mills/kWh) are calculated on the basis that the power unit size is the net power output after the addition of the pollution control systems. Actually, the electrical usage by the pollution control equipment after the ESP will result in a derating of the utility plant. To minimize iterative calculations, instead of derating the utility plant, the pollution control equipment is charged with purchased electricity. Maintenance costs are estimated to be 5% of the direct investment.

TABLE 11. COST FACTORS

1984 Utility Costs	
Electricity	$0.037/kWh
Steam	$2.70/MBtu
1984 Labor Costs	
Operating labor	$15.00/man-hr
Analyses	$21.00/man-hr
1984 Raw Material Costs	
Ammonia	$155.00/ton
Catalyst (Hitachi Zosen)	$700.00/ft^3

Indirect Costs--

Indirect costs cover levelized annual capital charges and overheads. The levelized annual capital charges consist of a sinking fund factor, allowance for interim replacement, property taxes, insurance, weighted cost of capital, income tax, credits for accelerated depreciation, and investment credit. the levelized annual capital charge as shown in Table 9 is 14.7%.

Overheads consist of plant, administrative, and marketing expenses. Plant and administrative overhead is 60% of conversion costs less utilities. The plant and administrative overheads include plant services such as safety, cafeteria, medical, plant protection, and general engineering (excluding maintenance). Fringe benefits are included in the base wage rates.

First-year revenue requirements using the 14.7% levelized capital charges are determined. In addition, levelized annual revenue requirements are calculated using a 10%/year discount factor, a 6%/year inflation factor, and a 30-year economic life that gives a 1.886 levelizing factor (8).

SYSTEMS ESTIMATED

Process descriptions, flowsheets, material balances, and major equipment lists and descriptions were prepared for each of the NO_x control methods evaluated in this study, with the exception of the ALNB. An equipment list is not available for the ALNB because of its early stage of development.

Two levels of NO_x reduction are examined. With a baseline emission of the 0.6 lb NO_2/MBtu (450 ppm at 3% O_2) NSPS, costs are determined to achieve a 50% NO_x reduction to 0.3 lb NO_2/MBtu (225 ppm at 3% O_2) for each of the three processes although 50% NO_x reduction is not typical for the Hitachi Zosen process. In addition, costs are determined for a 90% reduction in NO_x to 0.06 lb NO_2/MBtu (45 ppm at 3% O_2). The 90% NO_x reduction involves the following three process alternatives.

1. Moderate NO_x reduction achieved by the ALNB and the remaining NO_x reduction achieved by the Hitachi Zosen process.
2. Moderate NO_x reduction achieved by the Exxon process and the remaining NO_x reduction achieved by the Hitachi Zosen process.
3. 100% of the NO_x reduction achieved by the Hitachi Zosen process.

The levels of NO_x reduction assumed for each process and process combination are graphically illustrated in Figure 24. The Hitachi Zosen and Exxon processes are divided into major operational areas to facilitate cost comparisons.

ADVANCED LOW-NO_x BURNER

The flow diagram and material balance for the base case are shown in Figure 25 and Table 12 respectively. For this study an NO_x reduction to 0.3 lb NO_2/MBtu, from the baseline emission of 0.6 lb NO_2/MBtu, is believed to be a conservative objective compared with the research goal of 0.2 lb NO_2/MBtu.

The 500-MW ALNB system has 40 burners, each with 4 available tertiary ports. The central burner operates at 70% of the stoichiometric combustion air with an additional 50% supplied at the tertiary ports. The central burner, which is approximately 40 inches in diameter at the throat, contains

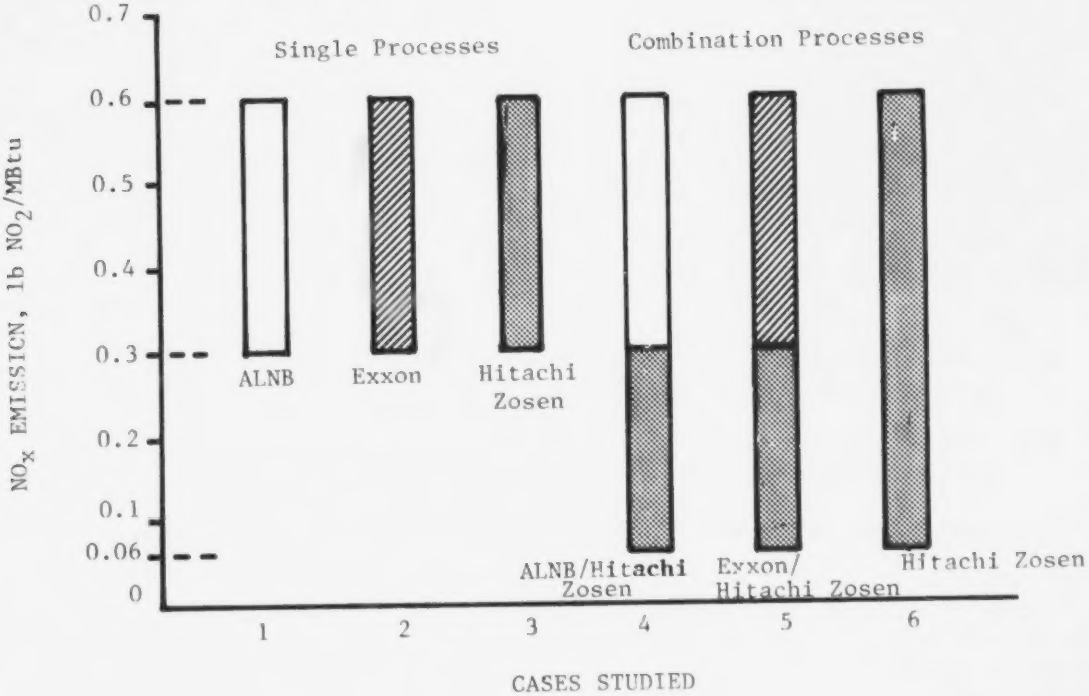

Figure 24. Assumed NO_x reduction for the six cases studied.

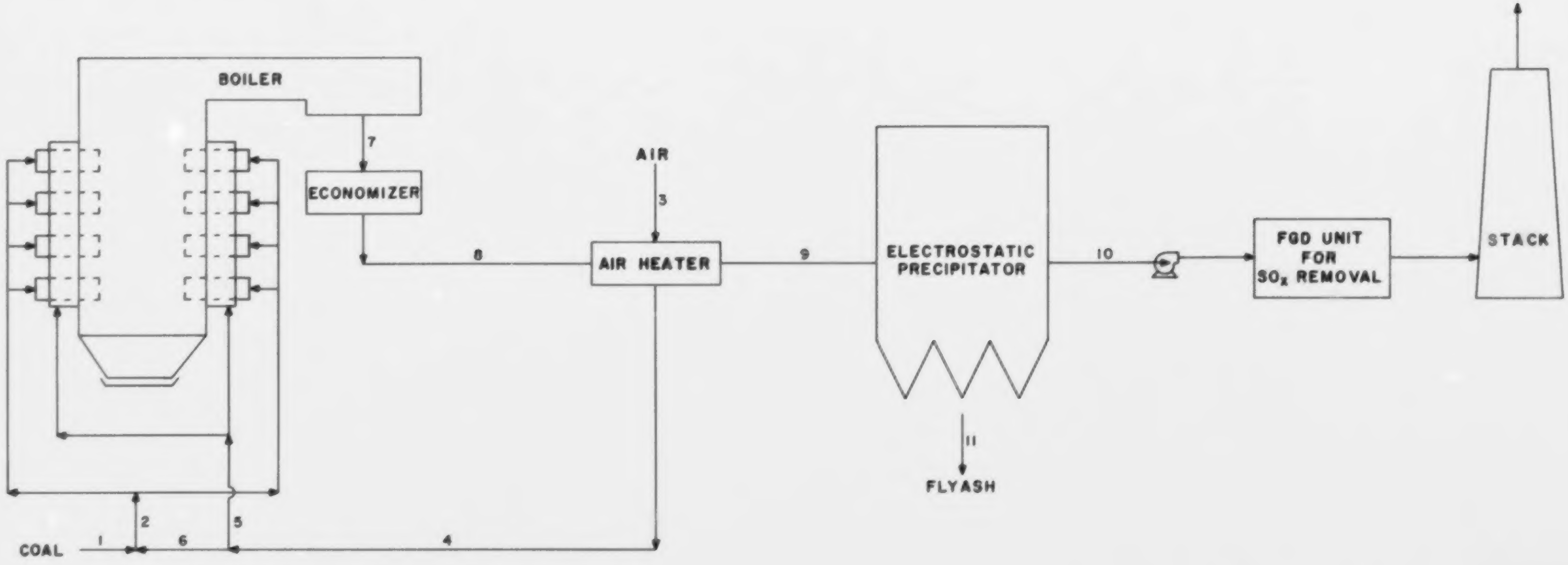
BOILER
7
ECONOMIZER
8
AIR
3
AIR HEATER
9
ELECTROSTATIC PRECIPITATOR
11
FLYASH
10
FGD UNIT FOR SO_x REMOVAL
STACK
COAL
1
2
6
5
4

Figure 25. Advanced low-NO_x burner flow diagram.

TABLE 12. ADVANCED LOW-NO$_x$ BURNER

MATERIAL BALANCE

	Stream	1	2	3	4	5
	Description	Coal to boiler	Coal and air to burner	Air feed to air heater	Combustion air to boiler	Air to windbox
1	Total stream, lb/hr	406,000	1,318,400	5,072,900	4,379,500	3,467,100
2						
3	sft^3/min (60°F)			1,121,300	968,100	766,400
4	Temperature, °F			80	535	535
5	Pressure, psig					
6						
7						
8						
9						
10						

	Stream	6	7	8	9	10
	Description	Air to burners	Flue gas to economizer	Flue gas to air heater	Flue gas to ESP	Flue gas to FGD unit
1	Total stream, lb/hr	912,400	4,772,100	4,772,100	5,465,500	5,416,600
2						
3	sft^3/min (60°F)	201,700	1,003,700	1,003,700	1,157,000	1,157,000
4	Temperature, °F	535		705	300	300
5	Pressure, psig					
6						
7						
8						
9						
10						

	Stream	11				
	Description	Fly ash from ESP				
1	Total stream, lb/hr	48,900				
2						
3	sft^3/min (60°F)					
4	Temperature, °F					
5	Pressure, psig					
6						
7						
8						
9						
10						

1						
2						
3						
4						
5						
6						
7						
8						
9						
10						

the primary annulus, the inner secondary annulus, and the outer secondary annulus. The primary annulus is approximately 20 inches in diameter and contains a conical diffuser fabricated from an abrasion-resistant metal to mix the primary air and entrained coal particles. The inner secondary annulus, which is constructed of stainless steel, contains stainless steel swirl vanes. These swirl vanes are used to control mixing between primary and secondary air. Additional combustion air is admitted through the outer secondary annulus, which is also fabricated from stainless steel. The tertiary ports, made of stainless steel, are located approximately one burner throat diameter from the central burner. A compartmented windbox constructed of carbon steel is used to aid in control of the combustion air flow.

The ALNB design using tertiary ports may create installation and structural support problems when retrofitted on existing boilers. However, on a new boiler, as is the case evaluated in this study, these problems may be avoided by design of a unit compatible with the ALNB.

EXXON PROCESS

In this study air is used as the carrier for the NH_3 (2% NH_3-in-air). Proprietary Exxon gas-phase mixing technology is used to disperse the NH_3 throughout the flue gas. An $NH_3:NO_x$ molar ratio of 1.5:1 is used to obtain a 50% NO_x reduction efficiency. NH_3 breakthrough (loss in the flue gas) is approximately 50 ppm. The Exxon process is not expected to increase the pressure drop of the boiler system, therefore no additional flue gas fan capacity is included. The main control criteria are based on boiler load.

The flow diagram and material balance for the base case are shown in Figure 26 and Table 13 respectively. Hydrogen addition is not used. The Exxon process is divided into two processing sections and the equipment assigned to the appropriate section. The equipment list and descriptions by area are presented in Table 14. The total land requirement is one acre.

NH_3 Storage and Injection

In the NH_3 storage and injection section a compressor (and spare) for unloading liquid NH_3 from truck or rail transport and a sufficient quantity of 250 psig storage tanks for a 30-day supply are included. Before NH_3 is injected into the flue gas, it is vaporized in a shell-and-tube steam-heated vaporizer and mixed with 25 psig air supplied by a compressor. There is one vaporizer and there are three air compressors, two operating and one spare. Each compressor handles 50% of the required capacity. Two zoned injection grids are included to accommodate flue gas temperature changes resulting from load changes as well as flue gas temperature variations across the injection plane.

Air Preheater Section

In the air preheater section two modified air heaters are provided. These incorporate possible changes in air heater design required to prevent adverse operational effects from $(NH_4)_2SO_4$ and NH_4HSO_4 deposits

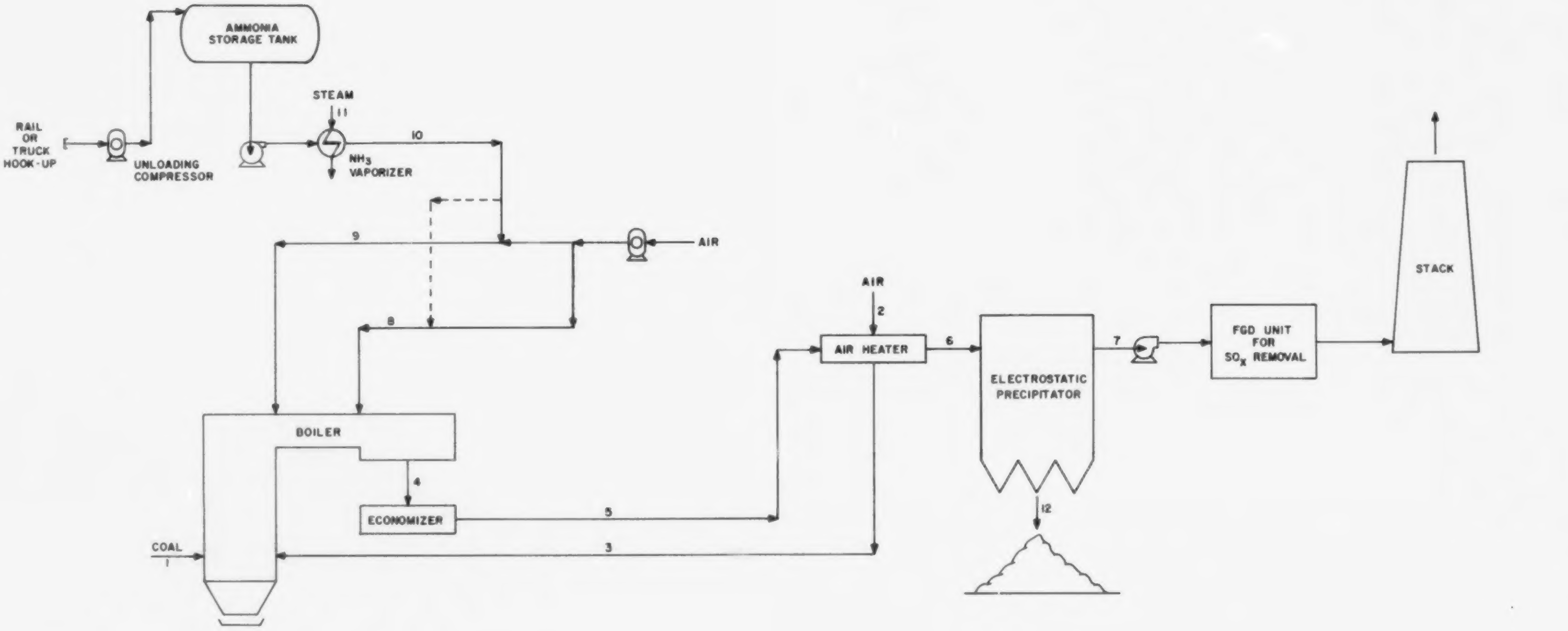
AMMONIA STORAGE TANK
RAIL OR TRUCK HOOK-UP
UNLOADING COMPRESSOR
STEAM
11
NH_3 VAPORIZER
10
9
AIR
8
BOILER
4
ECONOMIZER
5
COAL
1
3
AIR
2
AIR HEATER
6
ELECTROSTATIC PRECIPITATOR
12
7
FGD UNIT FOR SO_x REMOVAL
STACK

Figure 26. Exxon process flow diagram.

TABLE 13. EXXON

MATERIAL BALANCE

Stream		1	2	3	4	5
Description		Coal to boiler	Combustion air to air heater	Combustion air to boiler	Gas to economizer	Gas to air heater
1	Total stream, lb/hr	406,000	5,072,900	4,379,500	4,973,300	4,973,300
2						
3	sft^3/min (60°F)		1,121,300	968,100		1,048,400
4	Temperature, °F		80	535		705
5	Pressure, psig					
6						
7						
8						
9						
10						

Stream		6	7	8	9	10
Description		Gas to ESP	Gas to FGD unit	Air to idle injection grid	NH_3 and air to active injection grid	NH_3 from storage
1	Total stream, lb/hr	5,666,700	5,617,800	66,500	134,700	1,582
2						
3	sft^3/min (60°F)	1,201,700	1,201,700			
4	Temperature, °F	300	300			110
5	Pressure, psig					225
6						
7						
8						
9						
10						

Stream		11	12			
Description		Steam to vaporizer	Fly ash from ESP			
1	Total stream, lb/hr	1,100	48,900			
2						
3	sft^3/min (60°F)					
4	Temperature, °F	298				
5	Pressure, psig	50				
6						
7						
8						
9						
10						

1						
2						
3						
4						
5						
6						
7						
8						
9						
10						

TABLE 14. EXXON

EQUIPMENT LIST

Item (number): description	Total equipment cost, 1982 $
Area 1--NH_3 Storage and Injection	
1. Compressor, NH_3 unloading (2): Single cylinder, double acting, 300 sft^3/min at 250 psig, 30 psig suction, 125 hp, cast iron	61,500
2. Tank, NH_3 storage (9): Horizontal, 9 ft dia x 66 ft long, 30,000 gal, 250 psig, carbon steel	311,900
3. Vaporizer, NH_3 (1): Steam at 298°F, tube type, 29 ft^2, 0.50 MBtu/hr, carbon steel	6,900
4. Compressor, air (3): 22,900 aft^3/min at 25 psig, 14.7 psia suction, single stage, 2,250 hp	1,132,800
5. Injection grid, NH_3 and air (2):	320,400
6. Pump, NH_3 (2): 6 gpm, 0.5 hp, 28 ft head, carbon steel	3,000
Subtotal	1,836,500
Area 2--Air Preheater Section	
1. Air preheater (2): Modified, size 29.5 Ljungstrom air heater	509,000
2. Soot blower, steam (2): 20 ft, retractable, hot side of air heater, 120 lb/min steam	26,400
Subtotal	535,400[a]
Total, Areas 1-2	2,371,900

[a] Incremental cost resulting from modification of the air preheater system.

resulting from NH_3 breakthrough. Two soot blowers, one per air heater, are included for hot-side air heater cleaning. The modified design also allows for the combination of the intermediate and cold temperature sections into one continuous element as well as a potentially different element design. However, only the incremental cost of the modified air heater, above costs of the standard air heater, is included in the cost estimate. These costs may change as further testing and evaluations are completed with coal-fired flue gas.

HITACHI ZOSEN PROCESS

This is a dry NO_x FGT process for the SCR of NO_x with NH_3. Catalyst for the Hitachi Zosen process is designed to handle high particulate loading with a pressure drop of 2 to 3 inches of H_2O across the reactor. Therefore, flue gas from a coal-fired boiler may be fed directly to the reactor upstream of the air heater before particulate removal.

Two base cases for the Hitachi Zosen process are examined for FGT on a 500-MW coal-fired boiler with a 0.6 lb NO_2/MBtu baseline emission. One is 90% NO_x reduction from 0.6 lb/MBtu to 0.06 lb/MBtu by treatment of the entire flue gas stream. The other case is a 50% overall NO_x reduction from 0.6 lb/MBtu to 0.3 lb/MBtu by treatment of a portion of the flue gas at a 90% NO_x reduction level. (Economics for an 80% NO_x reduction case, 0.3 lb/MBtu to 0.06 lb/MBtu, are scaled from the 90% NO_x reduction case. The 80% reduction case is used in combination with the ALNB and the Exxon process to achieve an overall NO_x reduction of 90% from the 0.6 lb NO_2/MBtu baseline emission.)

For 90% NO_x reduction NH_3 is injected into the flue gas upstream of the reactor at an NH_3:NO_x molar ratio of 1:1. Air is mixed with the NH_3 (5% NH_3 in air) to obtain improved mixing with the flue gas. In the reactor NO_x is reduced by NH_3 to N_2 in the presence of the catalyst at a temperature between 600°F and 750°F. The area velocity (flow rate of gas/surface area of catalyst) is 24.3 $ft^3/hr-ft^2$ for 90% NO_x removal requiring 10,734 ft^3 of catalyst.

To obtain a net 50% NO_x reduction, 56% of the flue gas leaving the economizer is treated for 90% NO_x reduction; the remaining 44% of the flue gas is bypassed around the reactor and recombined with the treated flue gas. Operating conditions are the same as the 90% reduction case stated above except catalyst requirements are reduced to 6,105 ft^3.

The NH_3 flow rate is automatically controlled based on the flue gas flow rate to the reactor, reactor inlet and outlet NO_x concentration, and NH_3 outlet concentration. NH_3 level leaving the reactor is assumed to be less than 10 ppm. To prevent formation of $(NH_4)SO_4$ and NH_4HSO_3 at low boiler loads the catalyst bed temperature is controlled by bypassing a part of the high-temperature flue gas flow around the economizer to the reactor.

The catalyst is manufactured as individual units which are joined to form the required catalyst bed. Flue gas passes parallel to the catalyst surface. The catalyst composition has not been revealed for proprietary reasons; however, Hitachi Zosen does state that it is constructed of common material. The catalyst life is assumed to be one year because the guarantee by Hitachi Zosen is only one year (the actual life may be longer).

Process Description (90% NO_x reduction)

The flow diagram and material balance for the 90% NO_x reduction case are shown in Figure 27 and Table 15 respectively. The Hitachi Zosen 90% NO_x reduction process is divided into four processing sections and the equipment assigned to the appropriate section. The equipment list and descriptions by area are presented in Table 16. The total land requirement is 1.5 acres.

NH_3 Storage and Injection--

A compressor (and spare) for unloading liquid NH_3 from truck or rail transport and a sufficient quantity of 250 psig storage tanks to maintain a 30-day NH_3 supply are included. Before NH_3 is injected into the flue gas, it is vaporized in a shell-and-tube steam-heated vaporizer and mixed with air supplied by a small blower to form a 5% NH_3-in-air mixture. This is below the flammability limits for NH_3 in air (15.5% to 27.0%) and improves flow control and mixing. There is one vaporizer and one air-NH_3 blower for each of the two reactor trains with one additional air-NH_3 blower which serves as a spare. A pump is placed between the NH_3 storage tanks and the vaporizer of each train to aid in the control of NH_3 flow. A third pump serves as a spare. Two NH_3 injection grids, one per train, provide even distribution of the NH_3 in the flue gas before it enters the reactor.

Reactor Section--

Two reactors are provided, each handling 50% of the total flow. The reactors are fixed-bed type and constructed of carbon steel. Each reactor is provided with fly ash hoppers for collection of deposited fly ash and with two soot blowers for periodic cleaning. The catalyst consists of corrugated plates contained in units of 1 x 1 x 1 meter and 0.5 x 1 x 1 meter. These units are joined to form the appropriately sized catalyst bed. Two monorail cranes, one mounted on each reactor, are supplied to load and unload catalyst units.

Flue Gas Handling--

A larger ID fan is provided downstream of each ESP to compensate for the increased pressure drop created by the FGT system. However, only the incremental cost attributed to the NO_x removal system is included in the cost estimates. Because of the larger pressure drop, additional costs for bypass ducting around the ID fan to prevent boiler implosion are included with gas handling.

Air Preheater Section--

This area description is the same as previously given for the same area with the Exxon process.

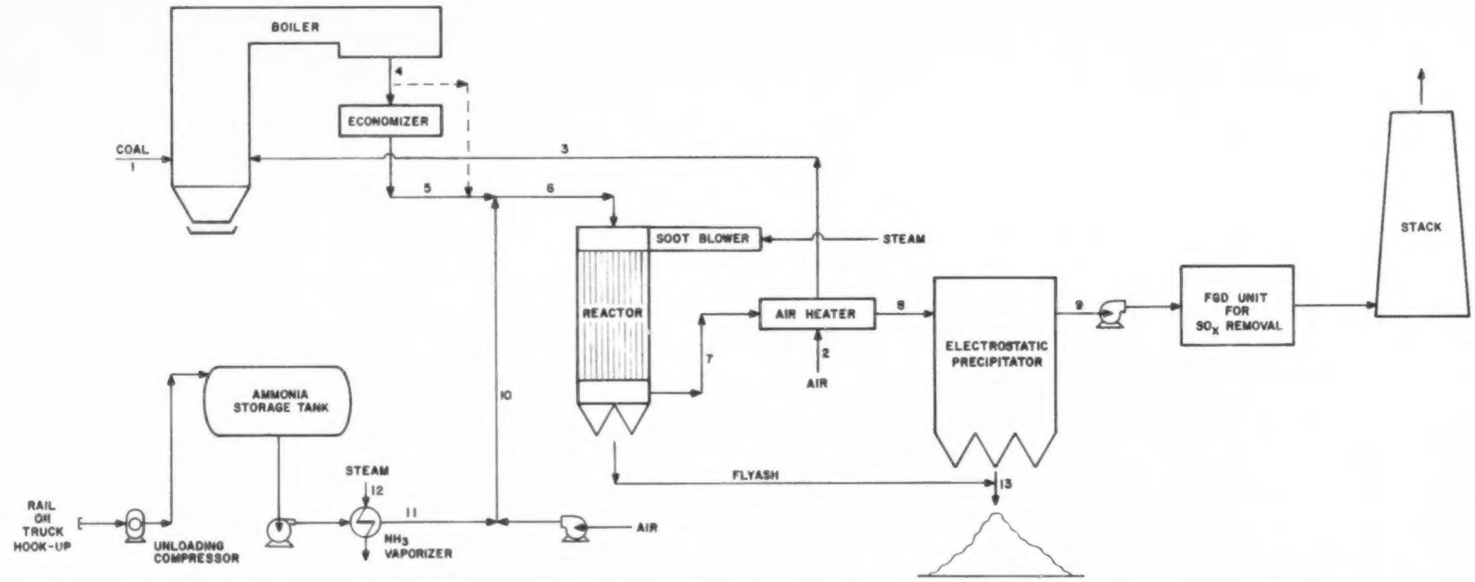
BOILER
ECONOMIZER
COAL
1
4
3
5
6
SOOT BLOWER
STEAM
REACTOR
AIR HEATER
8
2
AIR
7
10
ELECTROSTATIC PRECIPITATOR
9
FGD UNIT FOR SO_x REMOVAL
STACK
AMMONIA STORAGE TANK
STEAM
12
11
NH_3 VAPORIZER
AIR
FLYASH
13
RAIL OR TRUCK HOOK-UP
UNLOADING COMPRESSOR

Figure 27. Hitachi Zosen process (90% NO_x reduction) flow diagram.

TABLE 15. HITACHI ZOSEN (90% NO_x REDUCTION)

MATERIAL BALANCE

	Stream	1	2	3	4	5
	Description	Coal to boiler	Combustion air to air heater	Combustion air to boiler	Gas to economizer	Flue gas to reactor
1	Total stream, lb/hr	406,000	5,072,900	4,379,500	4,772,100	4,772,100
2						
3	sft^3/min (60°F)		1,121,300	968,100	1,003,700	1,003,700
4	Temperature, °F		80	535	890	705
5	Pressure, psig					
6						
7						
8						
9						
10						

	Stream	6	7	8	9	10
	Description	Flue gas - NH_3 mixture to reactor	Gas to air heater	Gas to ESP	Gas to FGD unit	NH_3 stream injected into flue gas
1	Total stream, lb/hr	4,807,600	4,807,600	5,501,000	5,452,100	35,500
2						
3	sft^3/min (60°F)	1,011,700	1,011,800	1,165,100	1,165,100	8,000
4	Temperature, °F	697	705	300	300	
5	Pressure, psig					
6						
7						
8						
9						
10						

	Stream	11	12	13		
	Description	NH_3 from storage	Steam to vaporizer	Fly ash from ESP		
1	Total stream, lb/hr	1,055	730	48,900		
2						
3	sft^3/min (60°F)					
4	Temperature, °F	110	298			
5	Pressure, psig	225	50			
6						
7						
8						
9						
10						

1						
2						
3						
4						
5						
6						
7						
8						
9						
10						

TABLE 16. HITACHI ZOSEN (90% NO_x REDUCTION)

EQUIPMENT LIST

Item (number): description	Total equipment cost, 1982 $
Area 1--NH_3 Storage and Injection	
1. Compressor, NH_3 unloading (2): Single cylinder, double acting, 300 sft^3/min at 250 psig, 30 psig suction, 125 hp, cast iron	61,500
2. Tank , NH_3 storage (6): Horizontal, 9 ft dia x 66 ft long, 30,000 gal, 250 psig, carbon steel	207,900
3. Vaporizer, NH_3 (2): Steam at 298°F, tube type, 10 ft^2, 0.33 MBtu/hr, carbon steel	7,400
4. Blower, NH_3 and air (3): 3,950 aft^3/min, ΔP 15 in. H_2O, 15 hp, carbon steel	17,900
5. Injection grid, NH_3 and air (2):	74,600
6. Pump, NH_3 (3): 2 gpm, 0.5 hp, 28 ft head, carbon steel	4,600
Subtotal	373,900
Area 2--Reactor Section	
1. Reactor (2): 55 ft x 33 ft x 41 ft high, 700°F operating temperature, carbon steel, insulated, with fly ash hoppers	2,054,200
2. Soot blower, steam (4): 33 ft, retractable, 870 lb/min steam	58,000
3. Reactor crane and hoist (2): 33 ft monorail, 2,500 lb capacity, 40 ft lift	56,200
Subtotal	2,168,400

(continued)

TABLE 16 (continued)

Item (number): description	Total equipment cost, 1982 $
Area 3--Flue Gas Handling	
1. Blower, flue gas (4): 468,261 aft^3/min, ΔP 22 in. H_2O, 2,500 hp, 316 stainless steel	467,700
Subtotal	467,700[a]
Area 4--Air Preheater Section	
1. Air preheater (2): Modified, size 29.5 Ljungstrom air heater	509,000
2. Soot blower, steam (2): 20 ft, retractable, hot side of air heater, 120 lb/min steam	26,400
Subtotal	535,400[b]
Total, Areas 1-4	3,545,400

a. Incremental cost resulting from increased flue gas pressure drop.
b. Incremental cost resulting from modification of the air preheater system.

Process Description (50% NO_x reduction)

The flow diagram and material balance for the 50% NO_x reduction case are shown in Figure 28 and Table 17 respectively. The Hitachi Zosen 50% NO_x reduction process is divided into four processing sections and the equipment assigned to the appropriate section. The equipment list and descriptions by area are presented in Table 18. The total land requirement is 1.5 acres.

NH_3 Storage and Injection--

The NH_3 storage and injection system for this case is similar to that previously described for the same area with the Hitachi Zosen 90% NO_x reduction case.

Reactor Section--

One reactor is provided handling 56% of the flue gas leaving the boiler. This reactor is the same as previously described for the same area in the Hitachi Zosen 90% NO_x reduction case.

Flue Gas Handling--

This area is the same as previously described for the Hitachi Zosen 90% NO_x reduction case.

Air Preheater Section--

This area is the same as that described for the Exxon process.

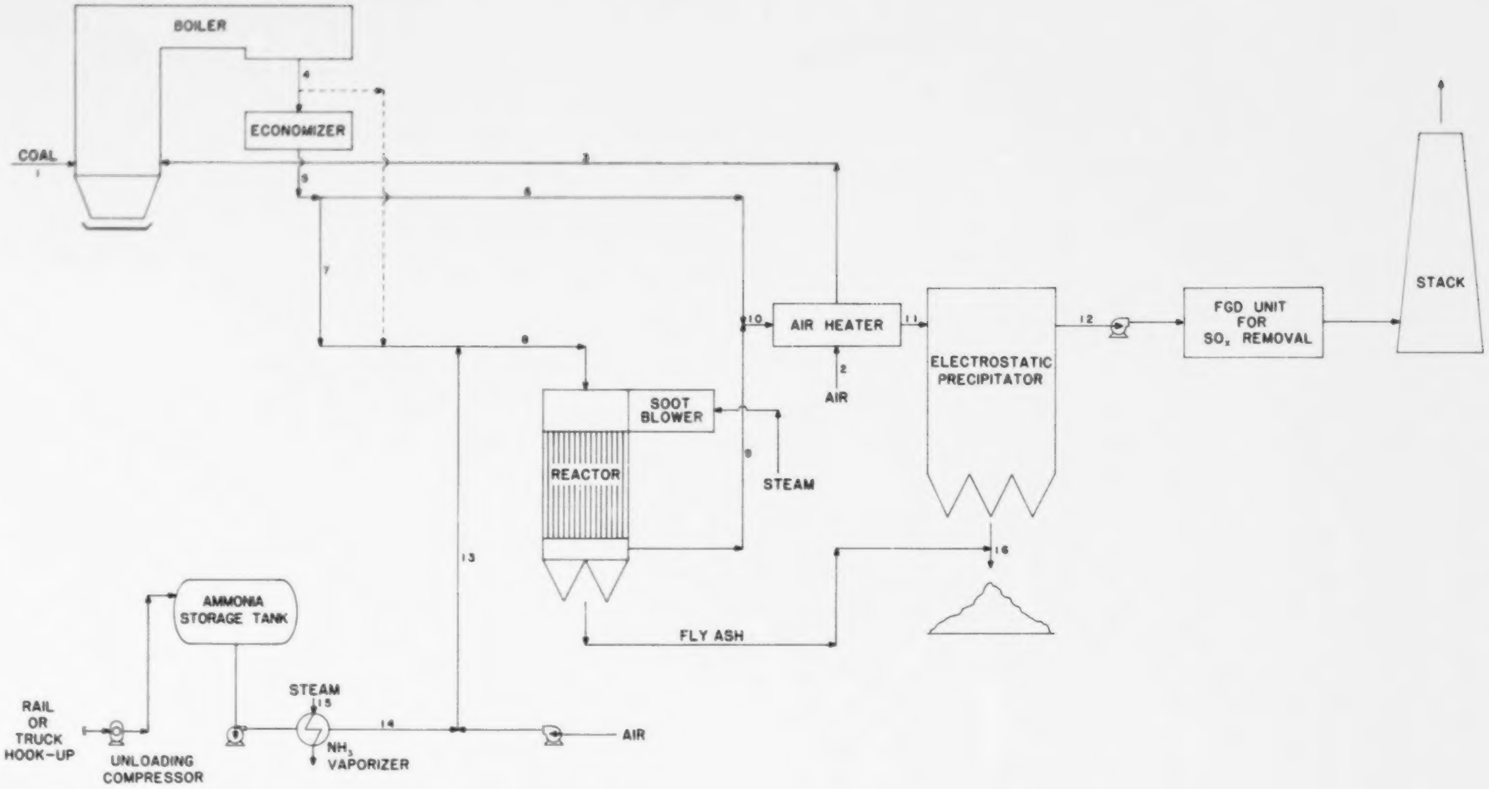
BOILER
4
ECONOMIZER
COAL
1
3
5
6
7
8
10
AIR HEATER
11
2
AIR
12
FGD UNIT
FOR
SO_2 REMOVAL
STACK
ELECTROSTATIC
PRECIPITATOR
SOOT
BLOWER
REACTOR
9
STEAM
13
16
FLY ASH
AMMONIA
STORAGE TANK
RAIL
OR
TRUCK
HOOK-UP
UNLOADING
COMPRESSOR
STEAM
15
NH_3
VAPORIZER
14
AIR

Figure 28. Hitachi Zosen process (50% NO_x reduction) flow diagram.

TABLE 17. HITACHI ZOSEN (50% NO_x REDUCTION)

MATERIAL BALANCE

	Stream	1	2	3	4	5
	Description	Coal to boiler	Combustion air to air heater	Combustion air to boiler	Gas to economizer	Gas exiting economizer
1	Total stream, lb/hr	406,000	5,072,900	4,379,500	4,772,100	4,772,100
2						
3	sft^3/min (60°F)		1,221,300	968,100	1,003,700	1,003,700
4	Temperature, °F		80	535	890	705
5	Pressure, psig					
6						
7						
8						
9						
10						

	Stream	6	7	8	9	10
	Description	Gas bypassing reactor	Flue gas to reactor	Flue gas - NH_3 mixture to reactor	Treated gas leaving reactor	Treated gas and bypass gas recombined
1	Total stream, lb/hr	2,118,800	2,653,300	2,673,000	2,673,000	4,791,800
2						
3	sft^3/min (60°F)	445,600	558,000	562,500	562,500	1,008,200
4	Temperature, °F	705	705	697	705	705
5	Pressure, psig					
6						
7						
8						
9						
10						

	Stream	11	12	13	14	15
	Description	Gas to ESP	Gas to FGD unit	NH_3 stream injected into flue gas	NH_3 from storage	Steam to vaporizer
1	Total stream, lb/hr	5,485,200	5,436,300	19,700	586	410
2						
3	sft^3/min (60°F)	1,161,500	1,161,500	4,400		
4	Temperature, °F	300	300		110	298
5	Pressure, psig				225	50
6						
7						
8						
9						
10						

	Stream	16				
	Description	Fly ash from ESP				
1	Total stream, lb/hr	48,900				
2						
3	sft^3/min (60°F)					
4	Temperature, °F					
5	Pressure, psig					
6						
7						
8						
9						
10						

TABLE 18. HITACHI ZOSEN (50% NO_x REDUCTION)

EQUIPMENT LIST

Item (number): description	Total equipment cost, 1982 $
Area 1--NH_3 Storage and Injection	
1. Compressor, NH_3 unloading (2): Single cylinder, double acting, 300 sft^3/min at 250 psig, 30 psig suction, 125 hp, cast iron	61,500
2. Tank, NH_3 storage (3): Horizontal, 9 ft dia x 66 ft long, 30,000 gal, 250 psig, carbon steel	104,000
3. Vaporizer, NH_3 (1): Steam at 298°F, tube type, 11 ft^2, 0.371 MBtu/hr, carbon steel	3,900
4. Blower, NH_3 and air (2): 4,385 aft^3/min, ΔP 15 in. H_2O, 15 hp, carbon steel	12,400
5. Injection grid, NH_3 and air (1):	37,300
6. Pump, NH_3 (2): 2 gpm, 0.5 hp, 28 ft head, carbon steel	3,100
Subtotal	222,200
Area 2--Reactor Section	
1. Reactor (1): 55 ft x 37 ft x 36 ft high, 700°F operating temperature, carbon steel, insulated, with fly ash hoppers	1,027,100
2. Soot blower, steam (2): 37 ft, retractable, 870 lb/min steam	31,200
3. Reactor crane and hoist (1): 37 ft monorail, 2,500 lb capacity, 35 ft lift	29,100
Subtotal	1,087,400

(continued)

TABLE 18 (continued)

Item (number): description	Total equipment cost, 1982$
Area 3--Flue Gas Handling	
1. Blower, flue gas (4): 466,814 aft^3/min, ΔP 21 in. H_2O, 2,250 hp, 316 stainless steel	222,700
Subtotal	222,700[a]
Area 4--Air Preheater Section	
1. Air preheater (2): Modified, size 29.5 Ljungstrom air heater	509,000
2. Soot blower, steam (2): 20 ft, retractable, hot side of air heater	26,400
Subtotal	535,400[b]
Total, Areas 1-4	2,067,700

a. Incremental cost resulting from increased flue gas pressure drop.
b. Incremental cost resulting from modification of the air preheater system.

RESULTS AND COMPARISON

Based on the design and economic premises and on the process equipment for each process, the capital investment, in 1982 dollars, and the annual revenue requirements, in 1984 dollars, were determined for the three 50% and three 90% NO_x reduction processes. Annual revenue requirements were determined for the first full year of operation. Levelized annual revenue requirements were determined using a 10%/year discount factor, a 6%/year inflation factor, and a 30-year economic life. The individual capital investment and annual revenue requirement tables for each process are shown in Appendix A. Costs for the ALNB are differential costs representing the additional capital investment and annual revenue requirements as compared with a boiler design using standard burners. Because of the different sources of data, simplifying assumptions made, and the necessity of projecting costs into the future, these estimates are considered to be accurate to an overall variation of -20% to +40% for the Exxon and Hitachi Zosen processes. For the ALNB the estimates are considered to be accurate to an overall variation of -20% to +100%.

The ALNB, Exxon, and Hitachi Zosen processes were evaluated at 50% NO_x reduction. This degree of NO_x reduction corresponds to the reduction of NO_x emissions from 0.6 to 0.3 lb NO_2/MBtu.

The ALNB/Hitachi Zosen, Exxon/Hitachi Zosen, and Hitachi Zosen processes were evaluated at 90% NO_x reduction. This degree of reduction lowers the NO_x emissions from 0.6 to 0.06 lb NO_x/MBtu.

CAPITAL INVESTMENT

The capital investment results for the 50% and 90% NO_x reduction cases are shown in Table 19.

Fifty Percent NO_x Reduction

Advanced Low-NO_x Burner--

The capital investment for the ALNB is $2.4M ($4.8/kW), as shown in Table A-1. Because of the burner's early stage of development, a breakdown of the direct and indirect investment is not available. This value is based on the assumption that the ALNB incremental costs are similar to the incremental costs incurred for design and application of the dual register burner/compartmented windbox system instead of a high-turbulence circular burner/single windbox system. Since development of the ALNB is being sponsored by EPA, a royalty fee is not charged for the technology.

TABLE 19. SUMMARY OF CAPITAL INVESTMENTS

Process	Capital investment, mid-1982$ M$	Capital investment, mid-1982$ $/kW
50% NO_x reduction		
ALNB	2.4	4.8
Exxon	9.9	19.7
Hitachi Zosen	15.7	31.4
90% NO_x reduction		
ALNB/Hitachi Zosen	25.9	51.8
Exxon/Hitachi Zosen	32.1	64.2
Hitachi Zosen	25.5	50.9

Exxon--

The capital investment for the Exxon process is $9.9M ($19.7/kW), as shown in Table A-3. Approximately one-third of the total capital investment is for the NH_3 storage and injection equipment ($3.3M). Royalties, at $1.5M, rank second to the NH_3 storage and injection system in contribution to the total capital investment. The remaining $5.1M of the capital investment is made up of various smaller charges, such as air preheater section ($0.6M), construction expenses ($0.6M), allowance for startup and modifications ($0.6M), and interest during construction ($1.0M).

Hitachi Zosen--

The capital investment for the Hitachi Zosen process is $15.7M ($31.4/kW), as shown in Table A-5. Equipment costs for the reactor and flue gas handling sections and the initial catalyst charge cost are the major contributors. The reactor section requires $2.2M for a reactor, soot blowers, and a monorail crane and hoist with the related accessories. The flue gas handling section contributes $2.1M to the total capital investment to cover the incremental cost for larger fans resulting from the increased flue gas pressure drop caused by the reactor system and for additional ductwork required to route the gas to and from the reactor.

Ninety Percent NO_x Reduction

ALNB/Hitachi Zosen--

To obtain the capital investment for the process combination, the capital investment for the ALNB (Table A-1) is added to the capital investment for the Hitachi Zosen 80% NO_x reduction case (Table A-7) to obtain the sum for the combined processes (Table A-9). The capital investment estimated for the combined ALNB and Hitachi Zosen processes is $25.9M ($51.8/kW). Breakdown of the direct and indirect investments is not shown in Table A-9 since these items are not available for the ALNB (see Table A-1). The initial catalyst charge cost at $5.0M is the largest cost item in the capital investment.

Exxon/Hitachi Zosen--

To obtain the capital investment for the combined processes, the capital investment for the Exxon process (Table A-3) is added to the 80% reduction Hitachi Zosen process capital investment (Table A-11) to obtain the sum for the two processes (Table A-13).

The capital investment for the combined Exxon and Hitachi Zosen processes is $32.1M ($64.2/kW). The four primary cost areas of the Exxon/Hitachi Zosen process are NH_3 storage and injection ($ 3.9M), the reactor section ($4.2M), flue gas handling ($3.1M), and the initial catalyst charge ($5.0M).

Hitachi Zosen--

The capital investment for the Hitachi Zosen process is $25.5M ($50.9/kW), as shown in Table A-15. Three areas contribute the majority of the capital investment. The reactor section is $4.2M, the flue gas handling section is $3.1M, and the initial catalyst charge cost is the largest of the three at $6.5M.

Overall Capital Investment Comparison

A comparison of the capital investments for each of the 50% and 90% NO_x reduction alternatives is shown in Table 20, along with identification of the major cost components.

For 50% NO_x reduction, the wide variation in capital investment is the result of the varied approaches to NO_x reduction and the equipment employed. The ALNB requires different burners and different windbox and boiler wall construction. The incremental cost differences for these changes are thought to be small. The Exxon process requires NH_3 storage, vaporization, and carrier air supply equipment and installation of two NH_3 injection grids in the boiler. The Hitachi Zosen process requires similar NH_3 storage, vaporization, and carrier air supply equipment and an injection grid. In addition it requires a reactor, catalyst, and additional fan capacity and ductwork for routing flue gas to and from the reactor.

While Hitachi Zosen has the highest capital investment for 50% reduction, it has the lowest capital investment for 90% reduction. The ALNB/Hitachi Zosen process is similar in cost for 90% reduction because the Hitachi Zosen capital investment for 80% reduction (0.3 reduced to 0.06 lb NO_2/MBtu) is not significantly less than for 90% reduction. As in all Hitachi Zosen capital investments, the initial catalyst charge cost is a major contributor. In the 80% and 90% reduction cases the difference in capital investment is primarily a result of the difference in catalyst requirements.

As shown in Table 20, the Exxon process requires more capital investment for the NH_3 storage and injection system than does the Hitachi Zosen

TABLE 20. CONTRIBUTION OF DIRECT INVESTMENT, ROYALTIES, AND CATALYST TO CAPITAL INVESTMENT

	50% reduction						90% reduction					
	ALNB[a]		Exxon		Hitachi Zosen		ALNB/ Hitachi Zosen[a]		Exxon/ Hitachi Zosen		Hitachi Zosen	
	M$	% of TCI	M$	% of TCI	M$	% of TCI	M$	% of TCI	M$	% of TCI	M$	% of TCI
Direct investment												
NH3 storage and injection			3.3	34	0.5	3			3.9	12	0.8	3
Reactor section			–		2.2	14			4.2	13	4.2	17
Flue gas fans			–		2.1	13			3.1	10	3.1	12
Air preheater section			0.6	6	0.6	4			0.6	2	0.6	2
Total process capital			3.9	40	5.4	34			11.8	37	8.7	34
Other capital charges												
Royalties	–	–	1.5	15	0.5	3	0.5	2	2.0	6	0.5	2
Catalyst	–	–	–	–	3.7	25	5.0	19	5.0	16	6.5	26
Subtotal of process capital, royalties, and catalyst	–	–	5.4	55	9.8	62	5.5	21	18.8	59	15.7	62
Other investments	–	–	4.5	45	5.9	38	20.4	79	13.3	41	9.8	38
Total capital investment (TCI)	2.4		9.9		15.7		25.9		32.1		25.5	

a. Breakdown of the direct investment for processes containing the ALNB is not available.

process. This is because of the larger NH_3 storage requirements, larger carrier air supply equipment, and the more complex injection grid system with the Exxon process.

The costs of air heater modifications, which are not an inherent part of the processes but may be required for process application to coal-fired boilers when NH_3 injection is used in NO_x control, are also included with the Exxon and Hitachi Zosen processes. These modifications may be required because of ammonium salt deposition in the air heater. The cost for air heater modifications used in this study are the same for both the Exxon and Hitachi Zosen processes, although the Exxon process has a much higher level of breakthrough NH_3 and there is more potential for problems from the ammonium salts deposition.

It should be noted that the royalties are a significant portion of the capital investment for the Exxon process. As shown in Table 20, the royalties are three times higher than those for the Hitachi Zosen process.

The capital investment for 50% NO_x reduction is considerably less than that for 90% reduction. The ratio of the lowest 90% reduction capital investment to the lowest 50% reduction capital investment is approximately eleven to one.

ANNUAL REVENUE REQUIREMENTS

The annual revenue requirements for each of the NO_x reduction processes are summarized in Table 21.

TABLE 21. SUMMARY OF ANNUAL REVENUE REQUIREMENTS

	Annual revenue requirements, 1984$			
	First year		Levelized	
Process	M$	Mills/kWh	M$	Mills/kWh
50% NO_x reduction				
ALNB	0.45	0.17	0.54	0.20
Exxon	3.4	1.2	5.1	1.9
Hitachi Zosen	8.0	2.9	13.0	4.7
90% NO_x reduction				
ALNB/Hitachi Zosen	11.5	4.2	18.4	6.7
Exxon/Hitachi Zosen	14.2	5.2	22.6	8.2
Hitachi Zosen	13.3	4.9	21.9	7.9

Fifty Percent NO_x Reduction

Advanced Low-NO_x Burner--

The first-year annual revenue requirements for the ALNB are $0.45M (0.17 mills/kWh), as shown in Table A-2. Levelized annual revenue requirements are $0.54M (0.20 mills/kWh). These are incremental costs above that required for presently available dual register burner systems capable of meeting the 1979 NSPS. Direct costs are low for the ALNB since utilities and raw materials, which normally contribute most of the direct cost, are not required. The only direct cost is $0.06M for maintenance, labor, and materials. Capital charges are the largest cost item of the annual revenue requirements.

Exxon--

The first-year annual revenue requirements for the Exxon process are $3.4M (1.2 mills/kWh), as shown in Table A-4. Levelized annual revenue requirements are $5.1M (1.9 mills/kWh). Raw materials and utilities are significant portions of the annual revenue requirements. A total of 4,351 tons of NH_3 is used each year at a yearly cost of $0.67M. Utilities at $0.76M are also a major factor. However, capital charges of $1.5M constitute the largest portion of the annual revenue requirements.

Hitachi Zosen--

The first-year annual revenue requirements for the Hitachi Zosen process are $8.0M (2.9 mills/kWh), as shown in Table A-6. Levelized annual revenue requirements are $13.0M (4.7 mills/kWh). Raw materials cost ($4.5M), particularly annual catalyst replacement cost ($4.3M), is the major cost item for the Hitachi Zosen process. Capital charges are also high at $2.3M, but this is significantly lower than the annual cost for replacement catalyst.

Ninety Percent NO_x Reduction

ALNB/Hitachi Zosen--

The annual revenue requirements for the combined ALNB and Hitachi Zosen processes are determined by the same method used to determine the capital investment. The ALNB annual revenue requirements (Table A-2) are added to the annual revenue requirements for Hitachi Zosen 80% NO_x reduction (Table A-8) to obtain the total annual revenue requirements (Table A-10) for a 90% overall NO_x reduction.

The first-year annual revenue requirements for the ALNB/Hitachi Zosen process are $11.5M (4.2 mills/kWh). The levelized annual revenue requirements are $18.4 (6.7 mills/kWh). Annual catalyst replacement at $5.8M is the largest contributor to the annual revenue requirements and the levelized capital charges are the next highest at $3.8M.

Exxon/Hitachi Zosen--

The annual revenue requirements for the combined Exxon and Hitachi Zosen processes are determined by adding the Exxon annual revenue requirements (Table A-4) to the annual revenue requirements of the Hitachi Zosen 80% NO_x reduction case (Table A-12) to obtain the total annual revenue requirements (Table A-14) for a 90% overall NO_x reduction.

The first-year annual revenue requirements for the Exxon/Hitachi Zosen process are $14.2M (5.2 mills/kWh). The levelized annual revenue requirements are $22.6M (8.2 mills/kWh). The annual catalyst replacement cost and the levelized capital charges are the two largest costs associated with the annual revenue requirements, $5.8M and $4.7M, respectively, but NH_3 at $0.9M and utilities at $1.4M are also significant.

Hitachi Zosen--

The first-year annual revenue requirements for the Hitachi Zosen process are $13.3M (4.9 mills/kWh), as shown in Table A-16. The levelized annual revenue requirements are $21.9M (7.9 mills/kWh). Raw material consumption is the major contributor to the total. Of the $7.9M for raw materials, annual catalyst replacement is $7.5M and is the single largest cost. Other significant cost items are the levelized capital charges ($3.7M) and utilities ($0.8M).

Overall Annual Revenue Requirements Comparison

A comparison of the annual revenue requirements for each of the 50% and 90% NO_x reduction alternatives is shown in Table 22, along with identification of the major cost components.

Annual revenue requirements for 50% NO_x reduction processes follow the same trend as capital investment, i.e., the ALNB has the lowest, the Exxon process is intermediate, and the Hitachi Zosen process has the highest. The ALNB has the lowest annual revenue requirements because no raw materials or utilities are required. Capital charges constitute most of the annual revenue requirements for the ALNB. This is in contrast to the Hitachi Zosen process in which raw materials, primarily replacement catalyst, are $4.5M and utilities are $0.5M.

As in the 50% reduction case, the annual revenue requirements are lowest for the 90% reduction process using the ALNB/Hitachi Zosen process. The Hitachi Zosen process by itself follows and the Exxon/Hitachi Zosen process has the highest annual revenue requirements. By using the ALNB in combination with the Hitachi Zosen process, the annual revenue requirements can be reduced below those of the Hitachi Zosen process alone. The decrease is a result of reduced NH_3 consumption, reduced replacement catalyst requirements, and reduced utility requirements.

Catalyst replacement requirements have a large effect on revenue requirements as can be seen when comparing the three 50% NO_x reduction cases. The cost is high and replacement must be made annually based on the Hitachi Zosen guarantee of a one-year catalyst life for applications to coal-fired flue gas. Since a one-year catalyst life is guaranteed it was used as a basis for the cost estimate; however, actual catalyst life could be longer. Should a two-year life be obtainable for the Hitachi Zosen process a significant savings can be realized in the annual revenue requirements. Table 23 shows that a two-year catalyst life will reduce the levelized annual revenue requirements of the Hitachi Zosen (50% NO_x reduction), ALNB/Hitachi

TABLE 22. CONTRIBUTION OF RAW MATERIALS AND UTILITIES TO ANNUAL REVENUE REQUIREMENTS

	50% reduction						90% reduction					
	ALNB		Exxon		Hitachi Zosen		ALNB/ Hitachi Zosen		Exxon/ Hitachi Zosen		Hitachi Zosen	
	M$	% of RR	M$	% of RR	M$	% of RR	M$	% of RR	M$	% of RR	M$	% of RR
Raw materials												
NH3	–		0.7	21	0.2	3	0.2	2	0.9	6	0.4	3
Catalyst	–		–	—	4.3	54	5.8	50	5.8	42	7.5	56
Total raw material cost			0.7	21	4.5	57	6.0	52	6.7	48	7.9	59
Utilities												
Steam	–		0.1	3	0.1	1	0.1	1	0.2	1	0.1	1
Electricity	–		0.7	21	0.5	6	0.6	5	1.3	9	0.6	5
Subtotal of raw materials and utilities	–		1.5	44	5.1	64	6.7	58	8.2	58	8.6	65
Other costs	0.5	100	1.9	56	2.9	36	4.8	42	6.0	42	4.7	35
First-year annual revenue requirements (RR)	0.5		3.4		8.0		11.5		14.2		13.3	
Levelized annual revenue requirements	0.5		5.1		13.0		18.4		22.6		21.9	

Zosen, and Hitachi Zosen (90% NO_x reduction) processes by 30% and the Exxon/Hitachi Zosen process by 24%. Even though this is a significant reduction in levelized annual revenue requirements for the processes containing catalyst, it is not sufficient to change the cost relationship of the processes. For 50% NO_x reduction the ALNB is still lowest followed by Exxon and Hitachi Zosen and for 90% NO_x reduction the ALNB/Hitachi Zosen remains the lowest followed by Hitachi Zosen and Exxon/Hitachi Zosen.

TABLE 23. THE EFFECT OF CATALYST LIFE ON

ANNUAL REVENUE REQUIREMENTS

Process	Annual Hitachi Zosen catalyst replacement cost, M$ 1-year catalyst life	Annual Hitachi Zosen catalyst replacement cost, M$ 2-year catalyst life	Levelized annual revenue requirements, M$ 1-year catalyst life	Levelized annual revenue requirements, M$ 2-year catalyst life
50% reduction				
Hitachi Zosen	4.3	2.1	13.0	9.0
90% reduction				
ALNB/Hitachi Zosen	5.8	2.9	18.4	12.9
Exxon/Hitachi Zosen	5.8	2.9	22.6	17.1
Hitachi Zosen	7.5	3.7	21.9	14.8

Since the Exxon process is a large consumer of NH_3 and electricity relative to the ALNB, the Exxon/Hitachi Zosen process has annual revenue requirements that are higher than the ALNB/Hitachi Zosen process.

The NH_3 consumption for the Exxon process is one and one-half times that of the Hitachi Zosen 90% NO_x reduction process and almost three times that of the Hitachi Zosen 50% NO_x reduction process. Therefore, as shown in Table 22, the annual NH_3 costs are greater for the Exxon process than for the Hitachi Zosen process in direct proportion to the consumption of NH_3.

As shown in Table 22, there are no significant differences in steam and electricity costs for the Exxon and Hitachi Zosen processes. The ALNB has no charges for utilities.

Annual revenue requirements for 50% NO_x reduction are considerably less than that for 90% reduction. The ratio of the lowest 90% reduction levelized annual revenue requirements to the lowest 50% reduction levelized annual revenue requirement is approximately 34 to 1.

As can be seen in Figure 29, 50% NO_x reduction cost is also lower in dollars per pound of NO_2 removed, with the exception of the Hitachi Zosen process. The main reason for the lower cost with 50% NO_x reduction, as explained earlier, is that the ALNB and Exxon processes do not require the expensive annual catalyst replacement needed for the Hitachi Zosen process. The Hitachi Zosen 50% NO_x reduction case has a slightly higher dollar per pound of NO_2 removed cost than the 90% reduction case for two reasons. First, there is some economy of scale in the capital investment for the 90% reduction case compared with the 50% reduction case. Therefore, the capital charges and maintenance, which are factored from the capital investment, are a smaller portion of the annual revenue requirements for the 90% reduction case. Also, certain cost items, such as labor, are the same for both 50% and 90% reduction cases making them a smaller cost (per pound of NO_x basis) for the 90% reduction case.

OVERALL CAPITAL INVESTMENT AND ANNUAL REVENUE REQUIREMENTS COMPARISON

Comparisons of the capital investment and levelized annual revenue requirements for each of the six NO_x control processes are shown in Figures 30 and 31. Also included in the figures are the effect of the accuracy range on the capital investment and levelized annual revenue requirements.

For 50% NO_x reduction the ALNB has the lowest capital investment and levelized annual revenue requirements. The Exxon process has the second lowest and Hitachi Zosen has the highest capital investment and levelized annual revenue requirements.

The capital investment of the ALNB/Hitachi Zosen and the Hitachi Zosen processes is almost equal for 90% NO_x reduction, but the levelized annual revenue requirements are lower for the ALNB/Hitachi Zosen process. In comparison with the above two processes, the Exxon/Hitachi Zosen process capital investment is substantially higher; however, the Exxon/Hitachi Zosen levelized revenue requirement is comparable.

Capital investment and levelized annual revenue requirements are significantly higher for 90% NO_x reduction than for 50% NO_x reduction.

ENERGY CONSUMPTION

Energy consumption for all of the NO_x reduction cases studied is less than 1% of the boiler capacity, as shown in Table 24. Energy requirements for the three 50% reduction cases range from none for the ALNB to 0.4% of the boiler capacity for the Exxon process. The range for 90% reduction is from 0.4% of the boiler capacity for the ALNB/Hitachi Zosen and Hitachi Zosen processes to 0.7% of the boiler capacity for the Exxon/Hitachi Zosen process.

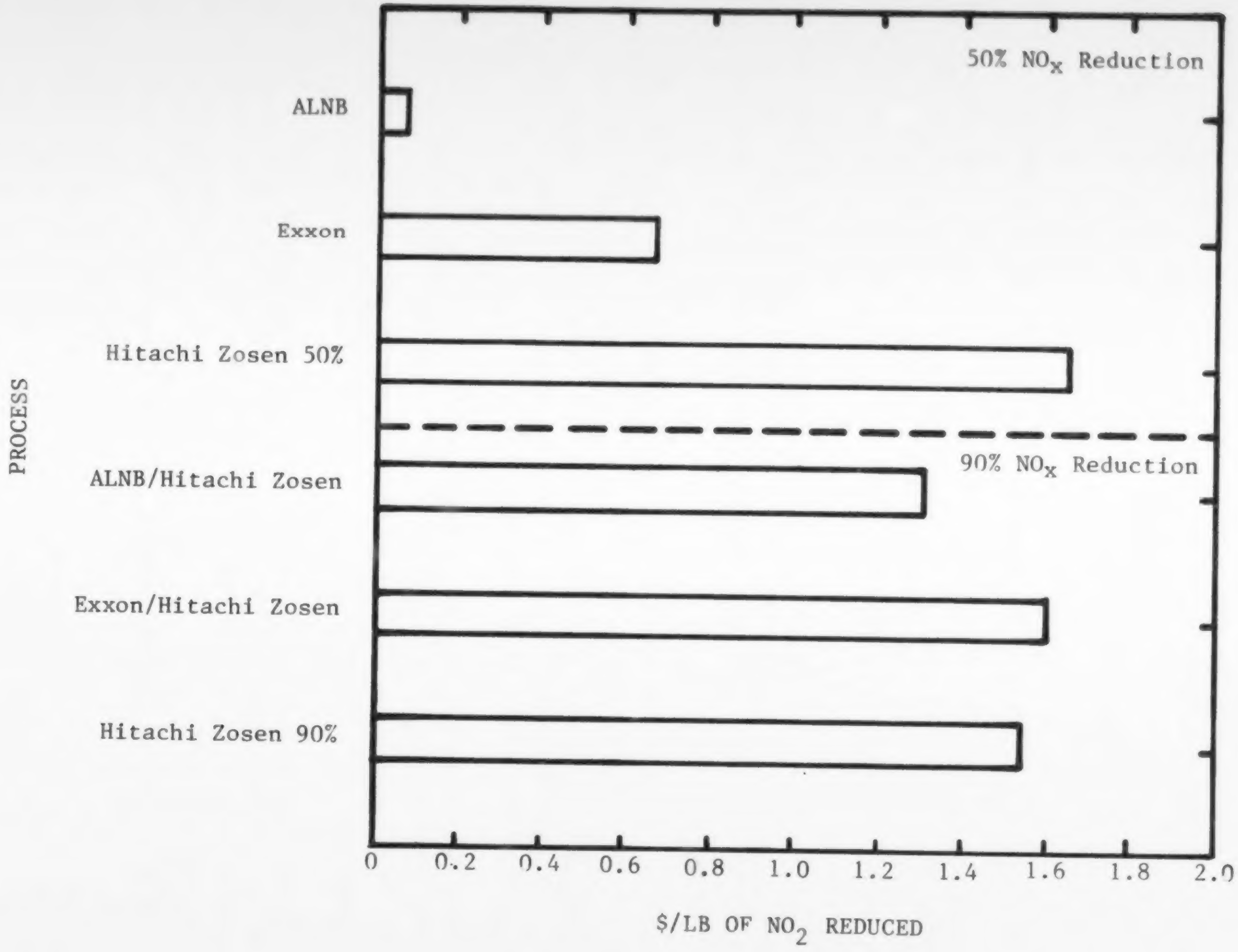

Figure 29. Cost for reduction of a pound of NO_x based on levelized annual revenue requirements.

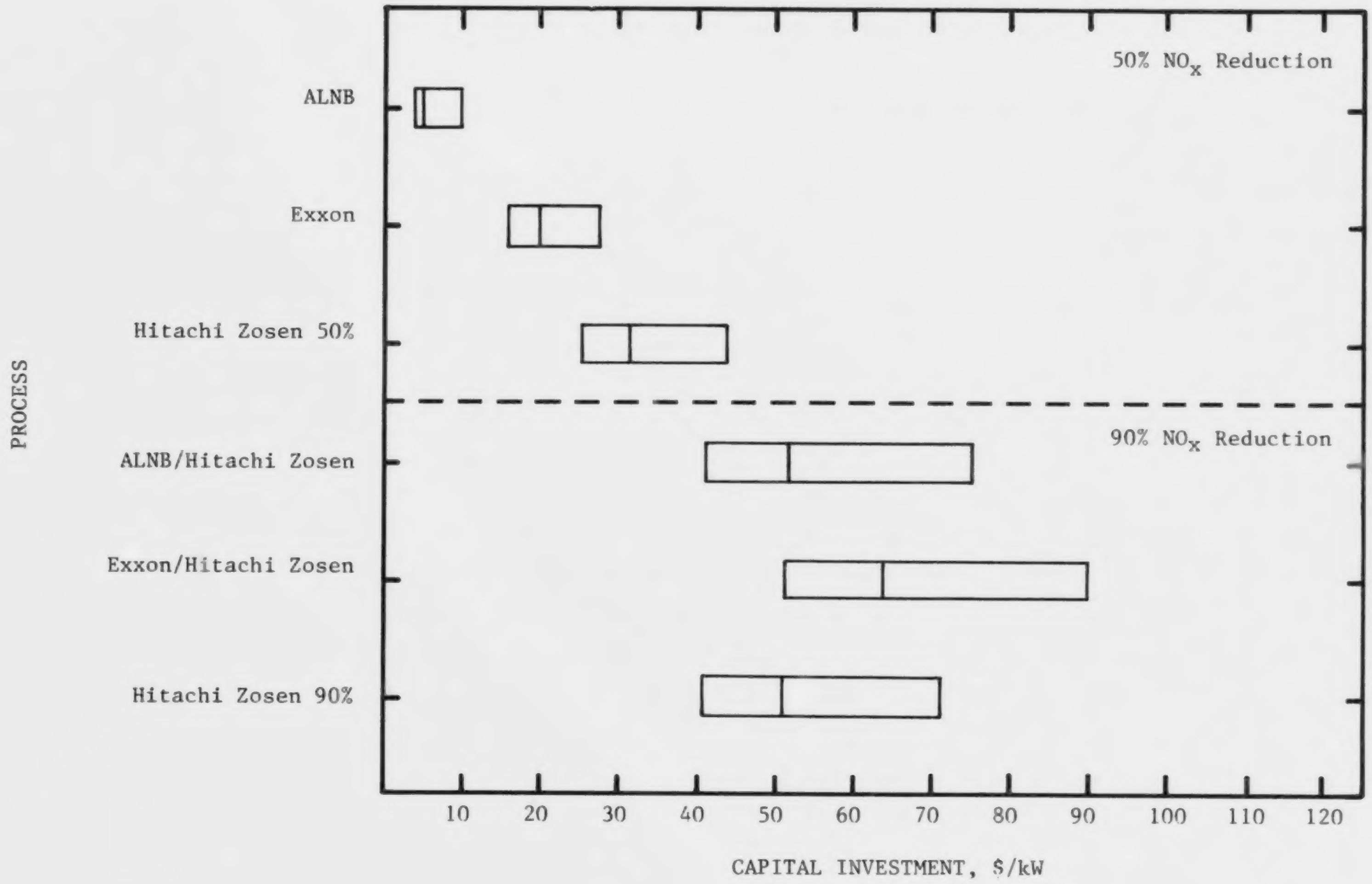

Figure 30. Capital investment comparison and accuracy range (based on a -20% to +40% range for Exxon and Hitachi Zosen processes and a -20% to +100% range for the ALNB).

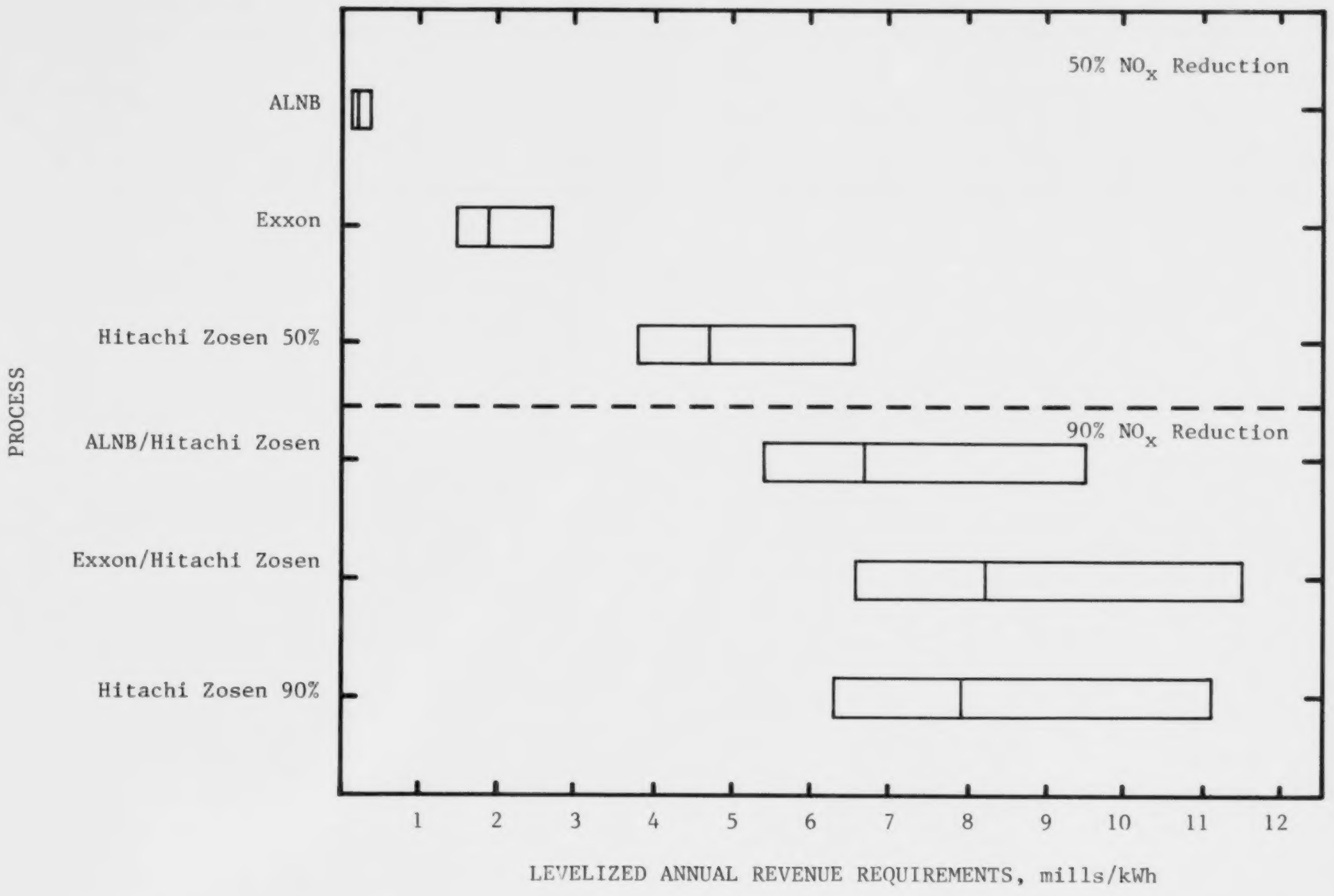

Figure 31. Levelized annual revenue requirements and accuracy range (based on a -20% to +40% range for Exxon and Hitachi Zosen processes and a -20% to +100% range for the ALNB).

TABLE 24. COMPARISON OF ENERGY REQUIREMENTS[a]

Process	MBtu/hr	Electricity, MBtu/hr	Total equivalent energy consumption,[b] percent of boiler capacity
50% Reduction			
Advanced Low-NO_x Burner	0.0	0.0	0.0
Exxon	5.7	11.5	0.4
Hitachi Zosen	6.0	7.7	0.3
90% Reduction			
ALNB/Hitachi Zosen	8.0	10.2	0.4
Exxon/Hitachi Zosen	11.7	21.7	0.7
Hitachi Zosen	10.9	10.3	0.4

a. Does not include energy requirement represented by raw materials.

b. Based on a 500-MW boiler, a gross heat rate of 9,500 Btu/kWh for generation of electricity, and a boiler efficiency of 90% for generation of steam.

Two of the three 90% NO_x reduction processes, the ALNB/Hitachi Zosen and the Hitachi Zosen, have estimated energy consumptions equivalent to the Exxon process (50% NO_x reduction) but the Exxon/Hitachi Zosen process is higher at 0.7% of the boiler capacity.

The NO_x control alternatives containing the Exxon process are the highest energy consumers at both the 50% and 90% NO_x reduction levels because of energy consumption of the large air compressors in the NH_3 storage and injection section.

CONCLUSIONS

The economic conclusions of this study are based on NO_x control technology at various early stages of development applied to a new power plant. Further development and retrofit applications could greatly alter both the absolute and relative costs of the processes. To develop accurate and timely economics in this rapidly evolving field, continued monitoring of developments in NO_x control technology is necessary.

For moderate NO_x reduction of 50%, the ALNB is by far the most economical alternative, even if its costs are to increase several times relative to the other processes.

The Hitachi Zosen process has a higher capital investment than the Exxon process at the 50% reduction level because of the initial catalyst charge, reactor, additional ductwork, and additional fan capacity required. It also has higher revenue requirements, primarily because of annual catalyst replacement costs, although its NH_3 requirements are much less than those of the Exxon process. Changes in catalyst cost or NH_3 consumption or cost would appreciably affect the cost relationship of these processes.

The royalties for the Exxon process are a significant portion of the capital investment.

For high NO_x reductions of 90% the combination of the ALNB/Hitachi Zosen process is the most cost effective alternative. Although the capital investment for the ALNB/Hitachi Zosen process is slightly higher than the capital investment for the Hitachi Zosen process, the annual revenue requirements are substantially lower. The magnitude of the difference in annual revenue requirements is large enough to overcome the slightly higher capital investment and make the ALNB/Hitachi Zosen process the most economically attractive.

The energy requirements for achieving 50% and 90% NO_x reduction are greater than that required for particulate removal except for the ALNB. However, energy requirements for NO_x reduction are still modest, much less than 1% of the boiler output, in comparison with the energy needed for removal of SO_2 from flue gas.

Catalyst cost is a very important economic factor with an SCR-type process. With the Hitachi Zosen process, the catalyst cost may represent as much as 25% of the capital investment and 35% of the levelized annual revenue requirement.

Catalyst life is also a very important economic factor. A two-year catalyst life will reduce the levelized annual revenue requirements of the Hitachi Zosen process by about 30%.

Since current technology requires SCR-type systems to achieve low emission levels (0.06 lb NO_2/MBtu), the cost for obtaining these low levels versus more moderate emission levels (0.3 lb NO_2/MBtu) are substantially greater. To achieve low emission levels as compared with moderate levels, based on the most economical alternatives, could require about a tenfold increase in capital investment and about a thirtyfold increase in levelized annual revenue requirements.

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APPENDIX A

CAPITAL INVESTMENT AND ANNUAL REVENUE REQUIREMENT TABLES

Appendix A contains the capital investment and annual revenue requirement tables for each of the processes evaluated in this study.

Process	Page
Advanced Low-NO$_x$ Burner	92
Exxon Thermal DeNO$_x$	94
Hitachi Zosen (50% NO$_x$ reduction)	96
Hitachi Zosen (80% NO$_x$ reduction) to be combined with the ALNB	98
Advanced Low-NO$_x$ Burner/Hitachi Zosen	100
Hitachi Zosen (80% NO$_x$ reduction) to be combined with Exxon	102
Exxon Thermal DeNO$_x$/Hitachi Zosen	104
Hitachi Zosen (90% NO$_x$ reduction)	106

TABLE A-1. CAPITAL INVESTMENT SHEET

ADVANCED LOW-NO_x BURNER

	Investment, $
Total fixed investment	1,888,000
Other Capital Investments	
Allowance for startup and modifications	189,000
Interest during construction	295,000
Royalties	0
Land	0
Working capital	49,000
Total Capital investment	2,421,000
Dollars of total capital per kW of generating capacity	4.8

Basis: New 500-MW north-central pulverized-coal-fired power unit; 9,500 Btu/kWh heat rate; 3.5% sulfur, 15.1% ash coal; 0.6 lb/MBtu NO_2 equivalent uncontrolled emission; 20% excess air to furnace, 39% total excess air; 1982 cost basis. Costs are the difference between those of the ALNB design and those of a boiler with standard burners.

TABLE A-2. ANNUAL REVENUE REQUIREMENTS

ADVANCED LOW-NO_x BURNER

	Total annual cost, $
Direct Costs - First Year	
Conversion costs	
Operating labor and supervision	0
Utilities	
Steam	0
Electricity	0
Maintenance	
Labor and material	61,000
Analyses	0
Total conversion costs	61,000
Total direct costs	61,000
Indirect Costs - First Year	
Overheads	
Plant and administrative (60% of conversion costs less utilities)	37,000
Marketing	0
Byproduct credit	0
Total first-year operating and maintenance costs	98,000
Levelized capital charges (14.7% of total capital investment)	356,000
Total first-year annual revenue requirements	454,000
Levelized capital charges (14.7% of total capital investment)	356,000
Levelized first-year operating and maintenance costs (1.886 first-year O and M)	185,000
Levelized annual revenue requirements	541,000

	M$	Mills/kWh
First-year annual revenue requirements	0.45	0.17
Levelized annual revenue requirements	0.54	0.20

Basis: Power unit as described in capital investment table, operating 5,500 hr/yr at full load; 1984 cost basis. Costs are the difference between those of the ALNB design and those of a boiler with standard burners.

TABLE A-3. CAPITAL INVESTMENT SHEET

EXXON THERMAL DENO$_x$

	Investment, $
Direct Investment	
NH3 storage and injection	3,268,000
Air preheater section	585,000
Total process capital	3,853,000
Services, utilities, and miscellaneous	231,000
Total direct investment	4,084,000
Indirect Investment	
Engineering design and supervision	286,000
Architect and engineering contractor	82,000
Construction expense	653,000
Contractor fees	204,000
Contingency	1,062,000
Total fixed investment	6,371,000
Other Capital Investments	
Allowance for startup and modifications	637,000
Interest during construction	994,000
Royalties	1,526,000
Land	5,000
Working capital	337,000
Total capital investment	9,870,000
Dollars of total capital per kW of generating capacity	19.7

Basis: New 500-MW north-central pulverized-coal-fired power unit; 9,500 Btu/kWh heat rate; 3.5% sulfur, 15.1% ash coal; 50% NO$_x$ reduction from 0.6 lb/MBtu NO$_2$ equivalent uncontrolled emission; and 20% excess air to furnace, 39% total excess air; 1982 cost basis.

TABLE A-4. ANNUAL REVENUE REQUIREMENTS

EXXON THERMAL $DENO_x$

	Annual quantity	Unit cost, $	Total annual cost, $
Direct Costs - First Year			
Raw materials			
NH3	4,351 tons	155/ton	674,400
Total raw materials cost			674,400
Conversion costs			
Operating labor and supervision	4,380 man-hr	15/man-hr	65,700
Utilities			
Steam	27888.7 MBtu	2.70/MBtu	75,300
Electricity	18.460×10^6 kWh	0.037/kWh	683,000
Maintenance			
Labor and material			204,200
Analyses	2,190 man-hr	21/man-hr	46,000
Total conversion costs			1,074,200
Total direct costs			1,748,600
Indirect Costs - First Year			
Overheads			
Plant and administrative (60% of conversion costs less utilities)			189,500
Marketing			0
Byproduct credit			0
Total first-year operating and maintenance costs			1,938,100
Levelized capital charges (14.7% of total capital investment)			1,450,900
Total first-year annual revenue requirements			3,389,000
Levelized capital charges (14.7% of total capital investment)			1,450,900
Levelized first-year operating and maintenance costs (1.886 first-year O and M)			3,655,300
Levelized annual revenue requirements			5,106,200

	M$	Mills/kWh
First-year annual revenue requirements	3.4	1.2
Levelized annual revenue requirements	5.1	1.9

Basis: Power unit as described in capital investment table, operating 5,500 hr/yr at full load; 1984 cost basis.

TABLE A-5. CAPITAL INVESTMENT SHEET

HITACHI ZOSEN (50% NO_x REDUCTION)

	Investment, $
Direct Investment	
NH_3 storage and injection	494,000
Reactor section	2,179,000
Flue gas fans	2,131,000
Air preheater section	585,000
Total process capital	5,389,000
Services, utilities, and miscellaneous	323,000
Total direct investment	5,712,000
Indirect Investment	
Engineering design and supervision	400,000
Architect and engineering contractor	114,000
Construction expense	914,000
Contractor fees	286,000
Contingency	1,485,000
Total fixed investment	8,911,000
Other Capital Investments	
Allowance for startup and modifications	891,000
Interest during construction	1,390,000
Royalties	458,000
Land	8,000
Working capital	339,000
Catalyst	3,681,000
Total capital investment	15,678,000
Dollars of total capital per kW of generating capacity	31.4

Basis: New 500-MW north-central pulverized-coal-fired power unit; 9,500 Btu/kWh heat rate; 3.5% sulfur, 15.1% ash coal; 50% NO_x reduction from 0.6 lb/MBtu NO_2 equivalent uncontrolled emission; and 20% excess air to furnace, 39% total excess air; 1982 cost basis.

TABLE A-6. ANNUAL REVENUE REQUIREMENTS

HITACHI ZOSEN (50% NO_x Reduction)

	Annual quantity	Unit cost, $	Total annual cost, $
Direct Costs - First Year			
Raw materials			
NH3	1,612 tons	155/ton	249,900
Catalyst			4,254,100
Total raw materials cost			4,504,000
Conversion costs			
Operating labor and supervision	4,380 man-hr	15/man-hr	65,700
Utilities			
Steam	29922.2 MBtu	2.70/MBtu	80,800
Electricity	12.368×10^6 kWh	0.037/kWh	457,600
Maintenance			
Labor and material			285,600
Analyses	2,190 man-hr	21/man-hr	46,000
Total conversion costs			935,700
Total direct costs			5,439,700
Indirect Costs - First Year			
Overheads			
Plant and administrative (60% of conversion costs less utilities)			238,400
Marketing			0
Byproduct credit			0
Total first-year operating and maintenance costs			5,678,100
Levelized capital charges (14.7% of total capital investment)			2,304,700
Total first-year annual revenue requirements			7,982,800
Levelized capital charges (14.7% of total capital investment)			2,304,700
Levelized first-year operating and maintenance costs (1.886 first-year O and M)			10,708,900
Levelized annual revenue requirements			13,013,600

	M$	Mills/kWh
First-year annual revenue requirements	8.0	2.9
Levelized annual revenue requirements	13.0	4.7

Basis: Power unit as described in capital investment table, operating 5,500 hr/yr at full load; 1984 cost basis.

TABLE A-7. CAPITAL INVESTMENT SHEET

HITACHI ZOSEN (80% NO_x REDUCTION)

(To be combined with the ALNB)

	Investment, $
Direct Investment	
NH_3 storage and injection	582,000
Reactor section	4,195,000
Flue gas fans	3,051,000
Air preheater section	585,000
Total process capital	8,413,000
Services, utilities, and miscellaneous	505,000
Total direct investment	8,918,000
Indirect Investment	
Engineering design and supervision	624,000
Architect and engineering contractor	178,000
Construction expense	1,427,000
Contractor fees	446,000
Contingency	2,319,000
Total fixed investment	13,912,000
Other Capital Investments	
Allowance for startup and modifications	1,391,000
Interest during construction	2,170,000
Royalties	458,000
Land	8,000
Working capital	485,000
Catalyst	5,034,000
Total capital investment	23,458,000
Dollars of total capital per kW of generating capacity	46.9

Basis: New 500-MW north-central pulverized-coal-fired power unit; 9,500 Btu/kWh heat rate; 3.5% sulfur, 15.1% ash coal; 80% NO_x reduction from 0.3 lb/MBtu NO_2 equivalent emission after 50% reduction from 0.6 lb/MBtu NO_2 equivalent with the ALNB; 20% excess air to furnace, 39% total excess air; 1982 cost basis.

TABLE A-8. ANNUAL REVENUE REQUIREMENTS

HITACHI ZOSEN (80% NO_x Reduction)

(To be combined with the ALNB)

	Annual quantity	Unit cost, $	Total annual cost, $
Direct Costs - First Year			
Raw materials			
NH_3	1,306 tons	155/ton	202,400
Catalyst			5,817,700
Total raw materials cost			6,020,100
Conversion costs			
Operating labor and supervision	4,380 man-hr	15/man-hr	65,700
Utilities			
Steam	39,532.8 MBtu	2.70/MBtu	106,700
Electricity	16.471×10^6 kWh	0.037/kWh	609,400
Maintenance			
Labor and material			445,900
Analyses	2,190 man-hr	21/man-hr	46,000
Total conversion costs			1,273,700
Total direct costs			7,293,800
Indirect Costs - First Year			
Overheads			
Plant and administrative (60% of conversion costs less utilities)			334,600
Marketing			0
Byproduct credit			0
Total first-year operating and maintenance costs			7,628,400
Levelized capital charges (14.7% of total capital investment)			3,448,300
Total first-year annual revenue requirements			11,076,700
Levelized capital charges (14.7% of total capital investment)			3,448,300
Levelized first-year operating and maintenance costs (1.886 first-year O and M)			14,387,200
Levelized annual revenue requirements			17,835,500

	M $	Mills/kWh
First-year annual revenue requirements	11.1	4.0
Levelized annual revenue requirements	17.8	6.5

Basis: Power unit as described in capital investment table, operating 5,500 hr/yr at full load; 1984 cost basis.

TABLE A-9. CAPITAL INVESTMENT SHEET

ADVANCED LOW-NO_x BURNER/HITACHI ZOSEN

	Investment, $
ALNB fixed investment	1,888,000
Hitachi Zosen fixed investment	13,912,000
Total fixed investment	15,800,000
Other Capital Investments	
Allowance for startup and modifications	1,580,000
Interest during construction	2,465,000
Royalties	458,000
Land	8,000
Working capital	534,000
Catalyst	5,034,000
Total Capital investment	25,879,000
Dollars of total capital per kW of generating capacity	51.8

Basis: New 500-MW north-central pulverized-coal-fired power unit; 9,500 Btu/kWh heat rate; 3.5% sulfur, 15.1% ash coal; 90% NO_x reduction from 0.6 lb/MBtu uncontrolled emission; 20% excess air to furnace, 39% total excess air; 1982 cost basis.

TABLE A-10. ANNUAL REVENUE REQUIREMENTS

ADVANCED LOW-NO_x BURNER/HITACHI ZOSEN

	Annual quantity	Unit cost, $	Total annual cost, $
Direct Costs - First Year			
Raw materials			
NH3	1,306 tons	155/ton	202,400
Catalyst			5,817,700
Total raw materials cost			6,020,100
Conversion costs			
Operating labor and supervision	4,380 man-hr	15/man-hr	65,700
Utilities			
Steam	39,532.8 MBtu	2.70/MBtu	106,700
Electricity	16.471×10^6 kWh	0.037/kWh	609,400
Maintenance			
Labor and material			506,900
Analyses	2,190 man-hr	21/man-hr	46,000
Total conversion costs			1,334,700
Total direct costs			7,354,800
Indirect Costs - First Year			
Overheads			
Plant and administrative (60% of conversion costs less utilities)			371,600
Marketing			0
Byproduct credit			0
Total first-year operating and maintenance costs			7,726,400
Levelized capital charges (14.7% of total capital investment)			3,804,300
Total first-year annual revenue requirements			11,530,700
Levelized capital charges (14.7% of total capital investment)			3,804,300
Levelized first-year operating and maintenance costs (1.886 first-year O and M)			14,572,200
Levelized annual revenue requirements			18,376,500

	M$	Mills/kWh
First-year annual revenue requirements	11.5	4.2
Levelized annual revenue requirements	18.4	6.7

Basis: Power unit as described in capital investment table, operating 5,500 hr/yr at full load; 1984 cost basis.

TABLE A-11. CAPITAL INVESTMENT SHEET

HITACHI ZOSEN (80% NO_x REDUCTION)

(To be combined with Exxon)

	Investment, $
Direct Investment	
NH3 storage and injection	582,000
Reactor section	4,195,000
Flue gas fans	3,051,000
Total process capital	7,828,000
Services, utilities, and miscellaneous	470,000
Total direct investment	8,298,000
Indirect Investment	
Engineering design and supervision	581,000
Architect and engineering contractor	166,000
Construction expense	1,328,000
Contractor fees	415,000
Contingency	2,158,000
Total fixed investment	12,946,000
Other Capital Investments	
Allowance for startup and modifications	1,295,000
Interest during construction	2,020,000
Royalties	458,000
Land	8,000
Working capital	457,000
Catalyst	5,034,000
Total capital investment	22,218,000
Dollars of total capital per kW of generating capacity	44.4

Basis: New 500-MW north-central pulverized-coal-fired power unit; 9,500 Btu/kWh heat rate; 3.5% sulfur, 15.1% ash coal; 80% NO_x reduction from 0.3 lb/MBtu NO_2 equivalent emission after 50% reduction from 0.6 lb/MBtu NO_2 equivalent with Thermal $DeNO_x$; 20% excess air to furnace, 39% total excess air; 1982 cost basis.

TABLE A-12. ANNUAL REVENUE REQUIREMENTS

HITACHI ZOSEN (80% NO_x Reduction)

(To be combined with Exxon)

	Annual quantity	Unit cost, $	Total annual cost, $
Direct Costs - First Year			
Raw materials			
NH3	1,306 tons	155/ton	202,400
Catalyst			5,817,700
Total raw materials cost			6,020,100
Conversion costs			
Operating labor and supervision	4,380 man-hr	15/man-hr	65,700
Utilities			
Steam	29,464.2 MBtu	2.70/MBtu	79,600
Electricity	16.471 x 10^6 kWh	0.037/kWh	609,400
Maintenance			
Labor and material			414,900
Analyses	2,190 man-hr	21/man-hr	46,000
Total conversion costs			1,215,600
Total direct costs			7,235,700
Indirect Costs - First Year			
Overheads			
Plant and administrative (60% of conversion costs less utilities)			316,000
Marketing			0
Byproduct credit			0
Total first-year operating and maintenance costs			7,551,700
Levelized capital charges (14.7% of total capital investment)			3,266,000
Total first-year annual revenue requirements			10,817,700
Levelized capital charges (14.7% of total capital investment)			3,266,000
Levelized first-year operating and maintenance costs (1.886 first-year O and M)			14,242,500
Levelized annual revenue requirements			17,508,500

	M $	Mills/kWh
First-year annual revenue requirements	10.8	3.9
Levelized annual revenue requirements	17.5	6.4

Basis: Power unit as described in capital investment table, operating 5,500 hr/yr at full load; 1984 cost basis.

TABLE A-13. CAPITAL INVESTMENT SHEET

EXXON THERMAL DENO$_x$/HITACHI ZOSEN

	Investment, $
Direct Investment	
NH3 storage and injection	3,850,000
Reactor section	4,195,000
Flue gas fans	3,051,000
Air preheater section	585,000
Total process capital	11,681,000
Services, utilities, and miscellaneous	701,000
Total direct investment	12,382,000
Indirect Investment	
Engineering design and supervision	867,000
Architect and engineering contractor	248,000
Construction expense	1,981,000
Contractor fees	619,000
Contingency	3,220,000
Total fixed investment	19,317,000
Other Capital Investments	
Allowance for startup and modifications	1,932,000
Interest during construction	3,014,000
Royalties	1,984,000
Land	13,000
Working capital	794,000
Catalyst	5,034,000
Total capital investment	32,088,000
Dollars of total capital per kW of generating capacity	64.2

Basis: New 500-MW north-central pulverized-coal-fired power unit; 9,500 Btu/kWh heat rate; 3.5% sulfur, 15.1% ash coal; 90% NO$_x$ reduction from 0.6 lb/MBtu NO$_2$ equivalent uncontrolled emission; 20% excess air to furnace, 39% total excess air; 1982 cost basis.

TABLE A-14. ANNUAL REVENUE REQUIREMENTS

EXXON THERMAL DENO$_x$/HITACHI ZOSEN

	Annual quantity	Unit cost, $	Total annual cost, $
Direct Costs - First Year			
Raw materials			
NH3	5,657 tons	155/ton	876,800
Catalyst			5,817,700
Total raw materials cost			6,694,500
Conversion costs			
Operating labor and supervision	8,760 man-hr	15/man-hr	131,400
Utilities			
Steam	57,352.9 MBtu	2.70/MBtu	154,900
Electricity	34.931×10^6 kWh	0.037/kWh	1,292,400
Maintenance			
Labor and material			619,100
Analyses	4,380 man-hr	21/man-hr	92,000
Total conversion costs			2,289,800
Total direct costs			8,984,300
Indirect Costs - First Year			
Overheads			
Plant and administrative (60% of conversion costs less utilities)			505,500
Marketing			0
Byproduct credit			0
Total first-year operating and maintenance costs			9,489,800
Levelized capital charges (14.7% of total capital investment)			4,716,900
Total first-year annual revenue requirements			14,206,700
Levelized capital charges (14.7% of total capital investment)			4,716,900
Levelized first-year operating and maintenance costs (1.886 first-year O and M)			17,897,800
Levelized annual revenue requirements			22,614,700

	M$	Mills/kWh
First-year annual revenue requirements	14.2	5.2
Levelized annual revenue requirements	22.6	8.2

Basis: Power unit as described in capital investment table, operating 5,500 hr/yr at full load; 1984 cost basis.

TABLE A-15. CAPITAL INVESTMENT SHEET

HITACHI ZOSEN (90% NO_x REDUCTION)

	Investment, $
Direct Investment	
NH3 storage and injection	840,000
Reactor section	4,195,000
Flue gas fans	3,051,000
Air preheater section	585,000
Total process capital	8,671,000
Services, utilities, and miscellaneous	520,000
Total direct investment	9,191,000
Indirect Investment	
Engineering design and supervision	643,000
Architect and engineering contractor	184,000
Construction expense	1,471,000
Contractor fees	460,000
Contingency	2,390,000
Total fixed investment	14,339,000
Other Capital Investments	
Allowance for startup and modifications	1,434,000
Interest during construction	2,237,000
Royalties	458,000
Land	8,000
Working capital	522,000
Catalyst	6,473,000
Total capital investment	25,471,000
Dollars of total capital per kW of generating capacity	50.9

Basis: New 500-MW north-central pulverized-coal-fired power unit; 9,500 Btu/kWh heat rate; 3.5% sulfur, 15.1% ash coal; 90% NO_x reduction from 0.6 lb/MBtu NO_2 equivalent uncontrolled emission; 20% excess air to furnace, 39% total excess air; 1982 cost basis.

TABLE A-16. ANNUAL REVENUE REQUIREMENTS

HITACHI ZOSEN (90% NO_x Reduction)

	Annual quantity	Unit cost, $	Total annual cost, $
Direct Costs - First Year			
Raw materials			
NH3	2,901 tons	155/ton	449,700
Catalyst			7,479,600
Total raw materials cost			7,929,300
Conversion costs			
Operating labor and supervision	4,380 man-hr	15/man-hr	65,700
Utilities			
Steam	53860.6 MBtu	2.70/MBtu	145,400
Electricity	16.533×10^6 kWh	0.037/kWh	611,700
Maintenance			
Labor and material			459,600
Analyses	2,190 man-hr	21/man-hr	46,000
Total conversion costs			1,328,400
Total direct costs			9,257,700
Indirect Costs - First Year			
Overheads			
Plant and administrative (60% of conversion costs less utilities)			342,800
Marketing			0
Byproduct credit			0
Total first-year operating and maintenance costs			9,600,500
Levelized capital charges (14.7% of total capital investment)			3,744,200
Total first-year annual revenue requirements			13,344,700
Levelized capital charges (14.7% of total capital investment)			3,744,200
Levelized first-year operating and maintenance costs (1.886 first-year O and M)			18,106,500
Levelized annual revenue requirements			21,850,700

	M$	Mills/kWh
First-year annual revenue requirements	13.3	4.9
Levelized annual revenue requirements	21.9	7.9

Basis: Power unit as described in capital investment table, operating 5,500 hr/yr at full load; 1984 cost basis.

APPENDIX B

CALCULATION OF PROCESS CAPITAL

Below is an illustration of how the process capital is obtained for the capital investment sheet from the equipment list. The NH_3 storage and injection area of the Hitachi Zosen 90% NO_x reduction process is used as an example.

The equipment list shown in Table B-1 represents the major equipment items in the NH_3 storage and injection section. These equipment items are costed on an erected basis, that is, the cost includes the labor required to place the equipment in position ready for operation. The total ($373,900) represents the total untaxed cost of the process equipment and is used as the basis for estimating the field equipment cost shown in Table B-2.

As can be seen in Table B-2, the untaxed field equipment cost (column B) is estimated as a percentage (column A) of the NH_3 storage and injection process equipment subtotal ($373,900). Untaxed field equipment cost is then broken down into material and labor by using the labor to material ratio (column C). Materials (column D) are then taxed at 4% to obtain sales tax (column E) which is added to the untaxed field equipment cost (column B) giving the field equipment cost (column F).

No taxes are charged to paint since material cost is insignificant compared with labor cost. Concrete foundations and excavation are not factored. Concrete is estimated for each equipment item and then totaled. Excavation is based on the quantity of land required.

Freight and sales tax on process equipment are also added to obtain the area direct investment. The weight of each piece of equipment is approximated and the total freight cost is calculated on a cost per weight basis. A sales tax of 4% is applied to the materials portion of process equipment.

The costs for process equipment, field equipment, freight, and process equipment sales tax are summed to give the area investment for NH_3 storage and injection.

Process equipment cost	$373,900
Field equipment cost	$395,500
Freight (based on estimated equipment weight)	$ 57,300
Process equipment sales tax	$ 12,900
Area investment	$839,600

The area investment is then rounded to $840,000 which is the NH_3 storage and injection investment listed in Table A-15.

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TABLE B-1. HITACHI ZOSEN (90% NO_x REDUCTION)

EQUIPMENT LIST

Item (number): description	Total equipment cost, 1982 $
Area 1--NH_3 Storage and Injection	
1. Compressor, NH_3 unloading (2): Single cylinder, double acting, 300 sft^3/min at 250 psig, 30 psig suction, 125 hp, cast iron	61,500
2. Tank , NH_3 storage (9): Horizontal, 9 ft dia x 66 ft long, 30,000 gal, 250 psig, carbon steel	207,900
3. Vaporizer, NH_3 (1): Steam at 298°F, tube type, 10 ft^2, 0.33 MBtu/hr, carbon steel	7,400
4. Blower, NH_3 and air (3): 3,950 aft^3/min, ΔP 15 in. H_2O, 15 hp, carbon steel	17,900
5. Injection grid, NH_3 and air (2):	74,600
6. Pump, NH_3 (2): 2 gpm, 0.5 hp, 28 ft head, carbon steel	4,600
Subtotal	373,900

TABLE B-2. BREAKDOWN OF FIELD EQUIPMENT COST

Field equipment	A % of area 1 subtotal	B Untaxed field equipment cost (labor + material)	C Labor/material	D Material	E Sales tax on material (4%)	F Field equipment cost
Piping and insulation	20	74,780	1.2	33,991[a]	1,360	76,100
Concrete foundations	–	103,300	2.756	27,503	1,100	104,400
Excavation, site preparation roads	–	–	–	–	–	10,000
Structural	5	18,695	1.7	6,924	277	19,000
Electrical	20	74,780	2.0	24,927	997	75,800
Instrumentation	15	56,085	0.484	37,793	1,512	57,600
Duct, chutes, expansion joints	10	37,390	7.0	4,674	187	37,600
Paint and miscellaneous	4	14,956	–	–	–	15,000
Total						395,500

[a]. Example calculation of material: material + labor = untaxed field equipment cost

material + 1.2 material = \$74,780

material = \$74,780/2.2 = \$33,991

TECHNICAL REPORT DATA

(Please read Instructions on the reverse before completing)

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16. ABSTRACT

The report is a technical discussion and preliminary economic evaluation of six NOx control methods: three at 50% NOx reduction, and three at 90%. The base-case power plant is a new 500-MW coal-fired unit emitting 0.6 lb NO2/million Btu in the flue gas. The three 50% NOx reduction processes are the EPA-sponsored advanced low-NOx burner (ALNB), the Exxon Thermal DeNOx process, and the Hitachi Zosen process, which have capital investments of \$4.8, \$19.7, and \$31.4/kW, respectively, and levelized annual revenue requirements of 0.20, 1.9, and 4.7 mills/kWh, respectively. For 90% NOx reduction, the ALNB process is combined with the Hitachi Zosen process, the Exxon process is combined with the Hitachi Zosen process, and the Hitachi Zosen process is used alone. Capital investment and levelized annual revenue requirements for these three processes are \$51.8/kW and 6.7 mills/kWh for the ALNB/Hitachi Zosen process, \$64.2/kW and 8.2 mills/kWh for the Exxon/Hitachi Zosen process, and \$50.9/kW and 7.9 mills/kWh for the Hitachi Zosen process alone. The ALNB, a combustion modification, is the least expensive NOx control method. As expected, the costs for obtaining high levels of NOx reduction (90%) are significantly greater than for more moderate levels (50%).

17. KEY WORDS AND DOCUMENT ANALYSIS

a. DESCRIPTORS	b. IDENTIFIERS/OPEN ENDED TERMS	c. COSATI Field/Group
Pollution	Pollution Control	13B
Nitrogen Oxides	Stationary Sources	07B
Coal	Advanced Low-NOx Burner (ALNB)	08G,21D
Combustion	Exxon Thermal DeNOx	21B
	Hitachi Zosen	
	Combustion Modification	

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